B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

OPEN ACCESS TRANSMISSION TARIFF – ATTACHMENT K

TRANSMISSION PLAN

Prepared by Transmission Planning
December 2019

2019

Table of Contents

List of Figures

T R A N S M I S S I O N P L A N N I N G

1. Executive Summary

This BPA Transmission Plan (T-Plan) is produced in accordance with the requirements of **BPA's Open Access Transmission Tariff Attachment K** (Attachment K) Planning Process. The planning process occurs on an annual basis and results in a public posting of this Transmission Plan. This plan documents the recommended transmission projects in BPA's service territory for the next ten years. It includes transmission needs identified from the annual reliability system assessment, transmission service requests, generation interconnection requests, and line-load interconnection requests. The various drivers and processes that occur during planning, as transmission needs are identified and plans of service are developed to meet those needs, are presented throughout this document. Most importantly, this T-Plan reflects our commitment to provide reliable service and meet our customer's needs efficiently and responsively. The intended audiences of this T-Plan are executives, organizations within BPA, and BPA customers and stakeholder who need to know BPA's future transmission plans.

The **Transmission Needs section** lists all the transmission needs identified over the 10-year horizon by load area and path. This section of information meets the Attachment K requirement to provide a brief narrative description of each transmission need, the preferred solution, an estimated cost, and proposed energization. In addition to this basic information, this year, more detailed information is provided in the Major Transmission Projects section for five major planned projects. There is the South Tri-cities Reinforcement to address near-term operations, reliability, and maintenance issues in the Tri-Cities area of Washington. The Raver 500/230 kV Transformer Addition has been studied as part of the sub-regional Puget Sound Area study team through ColumbiaGrid and is in the construction phase. The Longview Area 230/115 kV Transformer Addition is needed to maintain reliable load service in the area. The Schultz-Wautoma 500 kV Series Capacitor Addition is necessary to increase the South of Allston available transfer capability and improve operations and maintain flexibility for the South of Allston and I-5 paths. Finally, the Slatt-Series Capacitor Addition and Bakeoven Series Capacitor Optimization was initiated to expand Central Oregon load service capability and was energized in 2019.

As we turn our focus from identifying specific transmission needs to the bigger **transmission planning landscape,** there are significant industry factors at play and several regional entities that affect the manner in which the transmission system is planned. The Power Council's Seventh Power Plan and Mid-Term Assessment shows there have been additional retirements of coal generation and larger-than-expected reduction in the cost of wind and solar generating technologies; the market for natural gas and electric prices are low; and gas, wind and solar plants are displacing coal generation. As a result of these factors, the region may have a potential shortfall in resources needed to meet electricity demand after 2020 when the Boardman and Centralia 1 coal plants retire. In addition, the following coal plants are expected to retire: North Valmy (1-2021, 2-2025), Colstrip (1 and 2-2022), Centralia (2-2025) and Jim Bridger (1-2028, 2-2032). Also, the Pacific Northwest Utilities Conference Committee (PNUCC) produces a forecast that serves as a gauge for how much power will be needed and how utilities are meeting those needs. Their key trends show northwest utilities achieving carbon-reduction goals, while policymakers are aggressively enacting decarbonization legislation; utility planners are focused on summer and winter peak capacity needs; adequate reliable power is needed as coal plants retire; construction of new wind and other renewable resources cannot fully offset the loss of generation from coal plant retirements; and the feasibility of large-scale battery technology being deployed as a solution is being explored. Next, the Northwest Power Pool has recently embarked on a mission related to a comprehensive review of resource capacity adequacy in the region. According to NWPP, adequacy concerns were recently demonstrated on March 2019 when there was a gas pipeline interruption event and the west experienced extreme energy pricing throughout the entire interconnection. The NWPP will explore solutions to address the growing Northwest resource adequacy issue.

In addition to the broad industry issues described above, **The Western Energy Imbalance Market (EIM)** has gained significant interest as more of the region's utilities, public power utilities and power generators consider joining the market. The EIM is governed by the California Independent System Operator (CAISO) FERC-approved tariff and the ISO Department of Market Monitoring keeps a close watch on the efficiency and competitiveness of the EIM. BPA's EIM team began a stakeholder process to determine how and under which conditions BPA could join the EIM. In 2019 BPA signed an implementation agreement with the CAISO and record of decision in a move toward joining the Western Energy Imbalance Market in 2022. With the implementation agreement in place, BPA will begin work on Western EIM-specific projects identified in the grid modernization board map and develop detailed project plans with the CAISO to ensure the necessary steps are in place before the proposed go-live date in 2022.

Bonneville is transitioning reliability coordinator services to RC West from Peak Reliability on November 1, 2019. BPA has been extensively coordinating with RC West this year, which is operated by the California Independent System Operator. For Bonneville, the transition is part of the grid modernization project undertaken by a large team of employees from across the agency. The team addressed new technological requirements, data integrations, process changes, communication and training to interface with the new reliability coordinator. Beyond the reliability coordinator services, this effort better positions Bonneville to participate in the Western EIM if the agency decides to do so.

Finally, **Federal Energy Regulatory Commission Order 845** recently adopted reforms to the *pro forma* large generator interconnection procedures (LGIP) and the *pro forma* large generator interconnection agreement (LGIA) pursuant to which generators can interconnect with electric utility transmission grids. FERC's goal is to improve certainty for developers of electric generating and storage projects that interconnect to the transmission grid, promote informed decisions about generator interconnection costs and timing, and enhance the interconnection processes. As part of BPA rate case settlement agreement, BPA will post large generation interconnection study metrics on a publically facing site and begin implementing other 845 reforms in fiscal year 2020.

Transmission Planning's goal is to provide a reliable, flexible, environmentally responsible, and cost effective transmission system. Transmission Planning conducts the planning process in an open, coordinated and transparent manner through a series of open planning meetings that allow anyone to provide input into and comment on the development of the ten-year plan. Transmission Planning also strives to have a regionally coordinated system. In order to do just that BPA works with other regional entities such as the Pacific Northwest Utilities Conference Committee (PNUCC), Northern Tier Transmission Group, ColumbiaGrid and the newly formed NorthernGrid. The new regional planning organization, NorthernGrid, is intended to facilitate compliance with FERC requirements for utilities that are required to or elected to comply with such requirements, including cost allocation, when applicable.

2. Transmission Services

Transmission Services provides reliable open access, nondiscriminatory transmission service on the BPA transmission network for utilities, generators, and power marketers consistent with various regulatory requirements. This is done through marketing and selling transmission products and services, both regulated and unregulated, including transmission system planning, design, construction, operations, and maintenance. Transmission Services provides asset management services for the BPA transmission assets and the transmission assets of the Federal Columbia River Power System (FCRPS).

2.1 Transmission Business Model

The BPA Transmission Business Model is enabling economic growth in the region. BPA Transmission Services supports economic development and communicates with our customers about where the growth capability and pinch points are on the system.

BPA Transmission Services strives for excellence in the product portfolio through three approaches: product portfolio, infrastructure, and long-term viability. The product portfolio approach is to provide standardized options, value based price profiles, and integrated regional planning. In terms of infrastructure, BPA pursues advanced situational awareness, right-sized investment in assets and risk-based asset management. Long-term viability is achieved through integrated and efficient processes, data-driven decision making, and innovation and continuous improvement.

2.2 Planning & Asset Management Organization

Planning and Asset Management (PAM) is responsible for overseeing the transmission system asset management program to promote the reliability, compliance, efficiency and economical lifecycle of all transmission system physical assets. PAM oversees the development of both near and long-term activities and investments needed to meet BPA's long-term objectives and the development of capital and expense multi-year asset management strategies, plans, and budget forecasts. This is accomplished by evaluating the current condition and capability of the transmission system and evaluating the ability to meet predicted demands, desired performance, risks to meeting performance targets and least life cycle costs. Additionally, PAM oversees the development and implementation of the transmission system asset management system framework, including the development and implementation of asset management standards, policies, processes, procedures, and functions.

2.3 Attachment K Planning Process

Under BPA's Open Access Transmission Tariff Attachment K, the annual System Assessment considers needs driven by reliability, transmission needs driven by public policy requirements, and requested transmission service. The System Assessment Summary Report describes an evaluation of the transmission grid. The assessment begins with developing comprehensive computer models to test the adequacy of the planned grid under a wide variety of system conditions. This includes forecasts for loads, resources, and transmission facilities, which are key assumptions and the building blocks for the cases that are analyzed. BPA Transmission Planning engineers gauge the performance of the system using these models, and the results are compared to applicable standards and criteria adopted by the North American Electric Reliability Corporation (NERC), and the Western Electricity Coordinating Council (WECC). The NERC, WECC, and owner adopted standards require that the system be able to continue to function within a specific range of voltages and with transmission loading below facility ratings under a wide variety of operating conditions to meet existing obligations. These operating conditions include events such as a loss of a transmission line and/or substation facility under various seasons. Load area and path transmission needs identified during the annual system assessment are provided in the Transmission Needs section of this Transmission Plan.

2.4 FERC Order 845

Order 845
On April 19, 2018 the Federal Energy Regulatory Commission (FERC) adopted reforms to the *pro forma* large generator interconnection procedures (LGIP) and the *pro forma* large generator interconnection agreement (LGIA) pursuant to which generators can interconnect with electric utility transmission grids.

FERC is implementing reforms designed to improve certainty for developers of electric generating and storage projects that interconnect to the transmission grid, promote informed decisions about generator interconnection costs and timing, and enhance the interconnection processes.

The order revises the definition of generating facility to explicitly include energy storage. Also, energy storage is recognized as a resource in its own right rather than requiring storage to conform to rules designed for generators.

The order will allow interconnection agreements to be tailored to the level of service requested which can be lower than nameplate capacity. This became a prevalent issue with the rise of renewable resources such as wind and solar for which electrical output seldom equals nameplate capacity and for the ability of developers to include behind inverter batteries in their plans.

Another change brought about by the order is that it requires transmission providers to allow for provisional interconnection agreements for limited operation of a generating facility prior to the completion of the full interconnection process. The order also requires transmission providers to create a process for the interconnection customer to use surplus interconnection service at existing points of interconnection.

According to FERC, many interconnection customers experience delays and some interconnection queues have significant backlogs. These reforms are expected to provide interconnection customers with better information and more options for obtaining interconnection service. While BPA has been flexible in providing some of the reforms covered in Order 845, BPA will explore the timeline to officially implement the 845 reforms in the TC-22 process.

Order 845-A
On February 21, 2019, the Commission issued a follow-up order clarifying reforms from Order 845 and granting in part and denying in part requests for rehearing and clarification of its determinations in Order 845.

3. Transmission Planning Activities

Transmission Planning is responsible for planning BPA's transmission system and providing guidance to BPA Transmission Services' asset investment strategy. The core responsibilities include developing expansion plans for system reinforcements to meet transmission system needs for load growth, adequate transfer capability, and requests for generation interconnections, line and load interconnections, and long-term firm transmission service.

The main purpose of Transmission Planning is to identify solutions and develop plans of service to meet the future needs of the BPA transmission system. Transmission Planning identifies transmission projects based on three broad categories: area planning and system assessment, customer requests for transmission service on BPA's system, and generator and line and load interconnection customer requests. A brief description and timeline cycle is provided for each of these three main categories. The cycles and timelines may change from year to year.

Specifically, the area planning and system assessment have shifted the planning cycle to coordinate with related processes such as the Transmission Service Requests and Expansion Process (TSEP). The TSEP cluster study cycle has changed recently so that the process can be conducted annually. Finally the customer interconnection process was modified so that the scoping phase is conducted sooner, which is meant to minimize risk exposure. In some instances the scoping process may extend the cycle to complete a project.

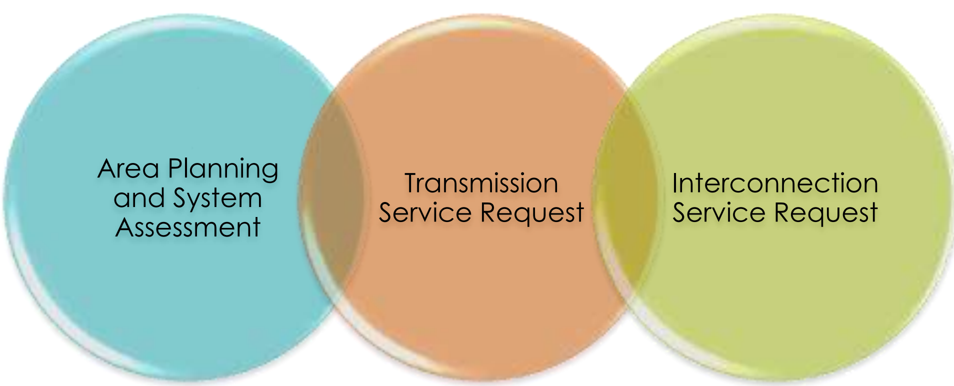


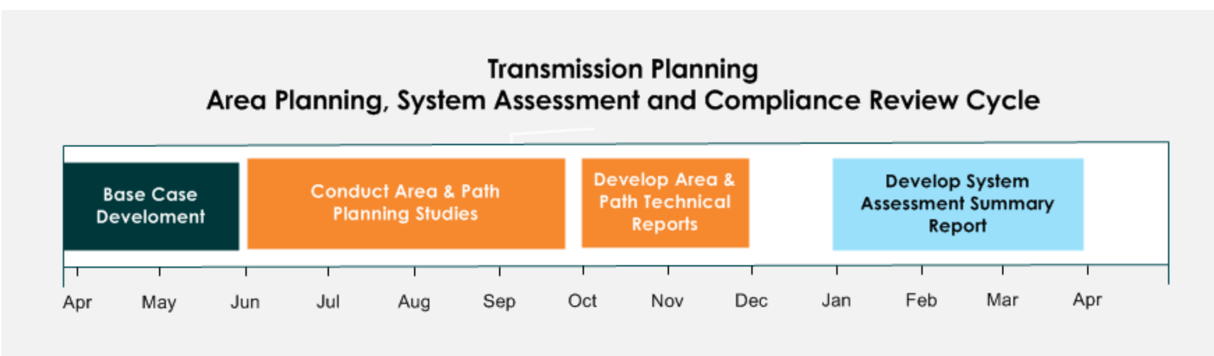
Figure 1 Planning Key Drivers Diagram

3.1 Area Planning and System Assessment

Each year, Transmission Planning conducts a comprehensive assessment of BPA's transmission system to ensure compliance with applicable North American Electric Reliability (NERC) Planning Standards and Western Electricity Coordinating Council (WECC) Regional Criteria. (WECC is the Regional Reliability Organization for NERC.) The NERC Standards TPL-001-4 require that BPA conduct an annual assessment to ensure that the BPA network is planned such that it can supply projected customer demand and projected firm transmission services over the expected range of forecast system demands while meeting the established reliability standards. Deficiencies in meeting these standards are noted and addressed in the System Assessment Summary Report. The assessment covers a 10-year planning horizon.

BPA's transmission system is divided into load areas and transfer paths. Studies for each load area and transfer path are conducted to ensure that existing and forecast load and projected firm transmission service can be served throughout the planning horizon and that existing corrective action plans, such as system reinforcements, are adequate. For each load area and transfer path, either new studies are conducted or qualified past studies are used to ensure that existing and forecast load and projected firm transmission service can be served throughout the planning horizon and that existing or newly identified corrective action plans, such as system reinforcements, are adequate. The NERC TPL-001-4 Requirement 1 states that past studies may be used to support the Planning Assessment if the study is five years old or less and no material modifications have occurred to the System represented in the study. Those individual load areas or transfer paths that rely on past studies include a technical rationale to show why the past studies can be relied upon for the current System Assessment.

To meet NERC Planning Standard TPL-001-4, Corrective Action Plans are developed if studies identify potential performance deficiences. These corrective action plans are required in order to provide acceptable performance for contingency events as well as all lines in-service conditions. With these corrective action plans, BPA's system performance is acceptable and meets the requirements of the TPL-001-4 Standard. The 2017 System Assessment identified three new corrective action plans – two in the Eugene area, and one in the SE Idaho / NW Wyoming area. The 2018 System Assessment did not identify any additional reliability projects as many of the area studies were still valid from the previous assessment. The 2019 System Assessment identified two corrective action plans: the Aberdeen Tap in the Southwest Washington Coast area and the Grand Coulee – Foster Creek Line Upgrade in the Southwest Washington Coast area. In addition, the following transmission needs were identified: South Tri-cities Reinforcement and the Red Mountain – Horn Rapids 115 kV Line Reconductor in the Tri-Cities area, the Conkelley Substation Retirement in the Northwest Montana area, and the Grand Coulee – Foster Creek 115 kV Line Upgrade in the Okanogan area.



3.2 Transmission Service & Commercial Assessment

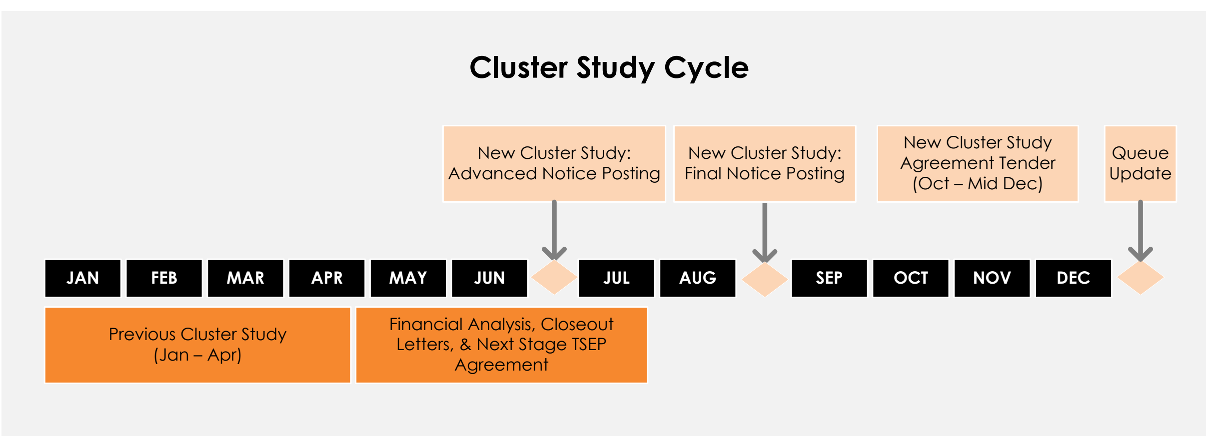
BPA customers may make a request for long-term transmission service (TSR). Transmission Planning's tariff obligations for TSRs include Sections 19 and 32 of the BPA Open Access Transmission Tariff (OATT). These sections pertain to additional study procedures for firm point-to-point (PTP) and network integration (NT) transmission service requests. Specifically Sections 19.1 through 19.6 and 19.10 of the OATT address the System Impact Study (SIS) and Facilities Study (FAS) procedures for firm PTP customers. Sections 32.1 through 32.5 address the SIS and FAS and Section 32.6 addresses the Cluster Study (CS) procedures. Transmission Planning conducts the additional studies as prescribed in the OATT.

Below is a brief description and diagram of the Commercial Assessment proposed timeline from June 2018 through May 2019. In June 2018, proposed model inputs were finalized. Then, BPA began use of the updated long-term available transfer capability (ATC) values in August to process the long term transmission service requests (TSRs) using both the Power Flow Distribution Factors (PTDF) calculation and an updated study-based methodology referred to as the Commercial Assessment.

The Commercial Assessment takes into consideration all known information about each TSR such as status of generator interconnection and/or historical generation patterns, association with rapid load growth or new load, and duplicative requests that may be present in the queue.

The expectation is that this study-based approach will result in some offers of transmission service made possible by maximizing the use of existing transmission system without infrastructure upgrades. Any such offers of transmission service will be made between August and December of 2018. Also, any TSRs that are not offered service through the Commercial Assessment by October 15th will be offered Cluster Study agreements, to identify Plan(s) of Service necessary to offer service.

The upcoming Cluster Study is expected to begin January 2019 and conclude in May 2019 at which time a Cluster Study Report is finalized. Transmission Planning produces a Cluster Study report which provides the findings of the analysis and power flow modeling that is conducted. A Cluster Study determines what transmission expansion, if any, is required to accommodate customer requests for long-term firm transmission service over the Bonneville network. Results of the Cluster Study will be made available in a similar manner as past studies.



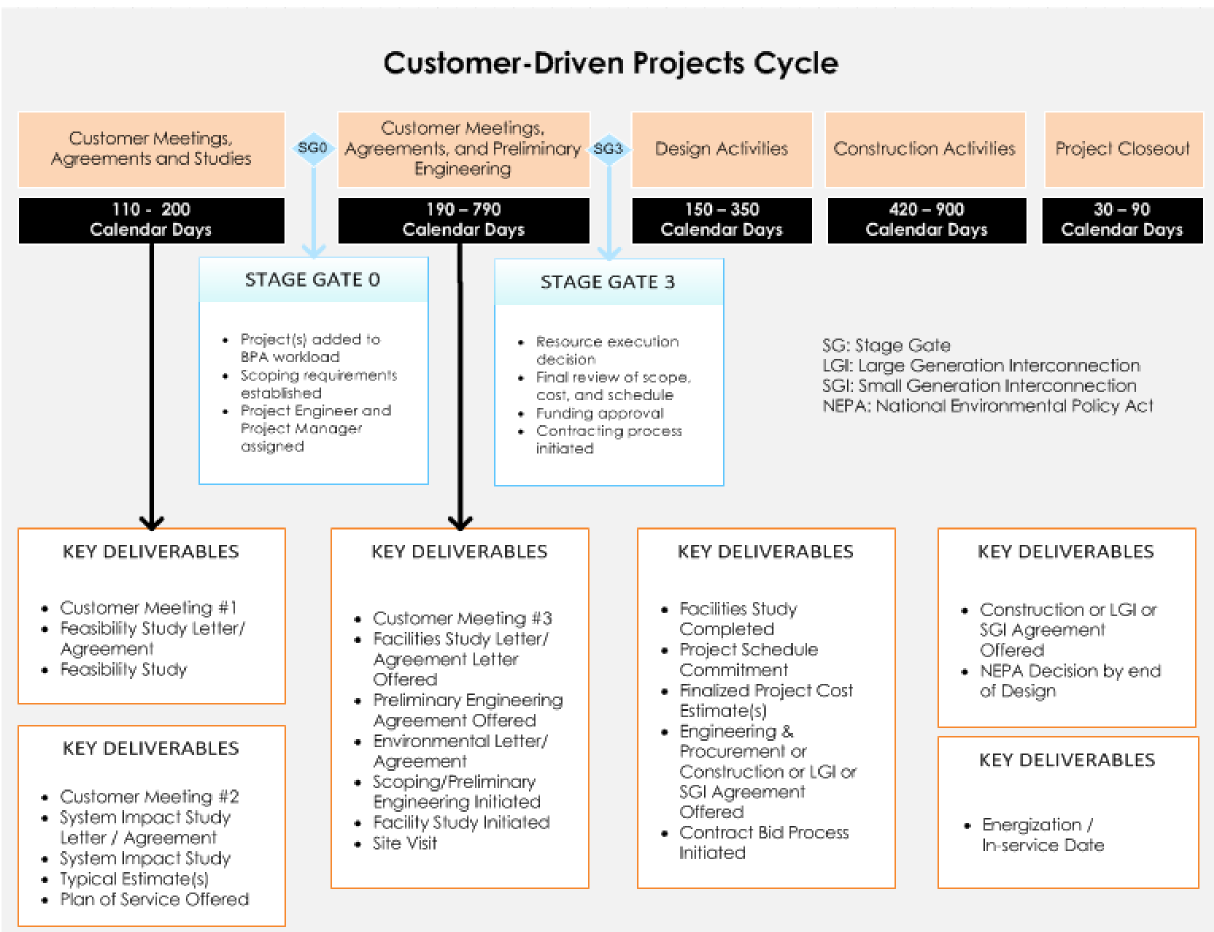
3.3 Interconnection Requests Studies

Customers may request new points of interconnection on BPA's transmission system. Line or load interconnections (LLI) are typically for new load additions or to allow the customer to shift to different points on their system. BPA customers may also request service to connect to BPA's system for new generation. BPA processes Generator Interconnection (GI) requests according to Attachment L Large Generator Interconnection Process (LGIP) and Attachment N Small Generator Interconnection Process (SGIP) of the BPA OATT.

Transmission Planning conducts a series of up to three studies for Generation and Line and Line Interconnection requests which are the feasibility, system impact, and facility study. These studies are performed after a customer has signed an agreement for each study.

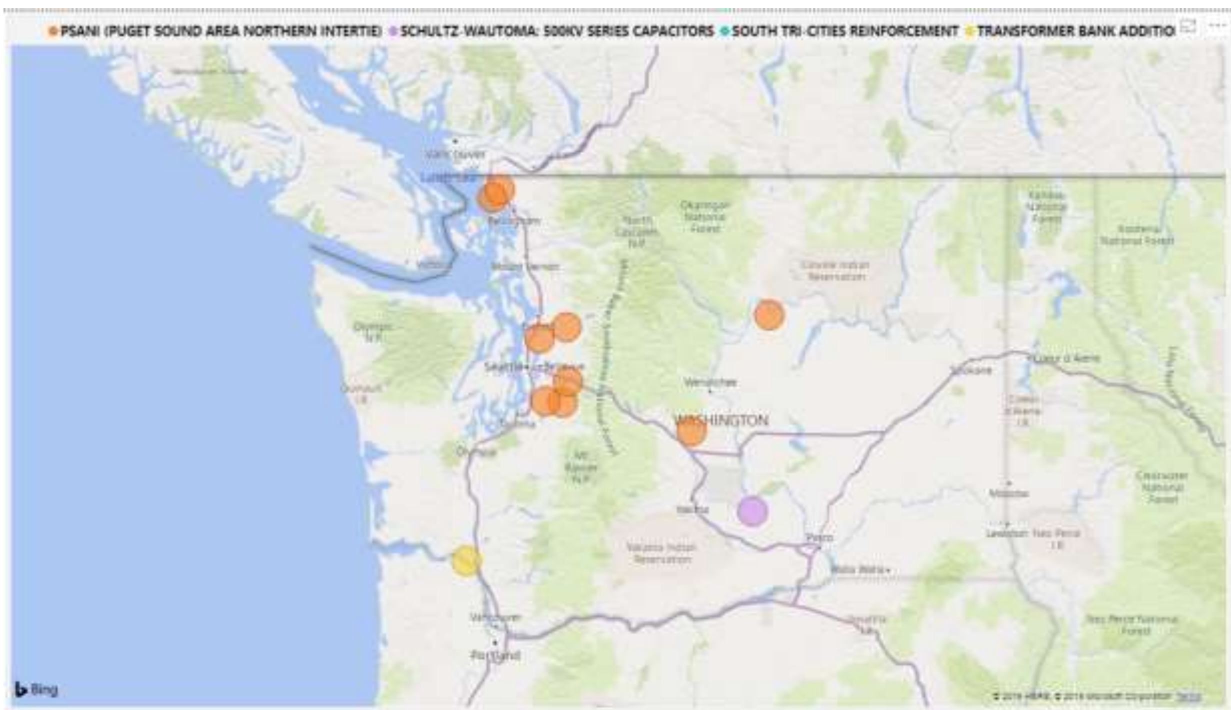
The interconnection queue is available at http://www.oasis.oati.com/bpat/index.html. The Capital Investment Acquisition Process and Customer Deliverables Diagram is available on BPA's web site at https://www.bpa.gov/transmission/Doing%20Business/Interconnection/Documents/capital-investment-acquisition-process-customer-deliverables.pdf

The customer driven projects process below shows typical or expected timelines for each of the phases of project development. BPA has modified its scoping process and in some instances the time to complete a project may take longer than it has in previous years.



4. Major Transmission Projects

Major transmission expansion projects with a plan of service shown in the map below include: PSANI or Raver 500/230 kV Transformer Addition, Schultz – Wautoma 500 kV Series Capacitor Addition, South Tri-Cities Reinforcement, and the Longview Transformer Bank Addition. Another major transmission project is the Slatt Series Capacitor Addition and Bakeoven Series Capacitor Upgrade in the Central Oregon Area. Below is more detailed information about each of these major transmission projects.



4.1 South Tri-Cities Reinforcement

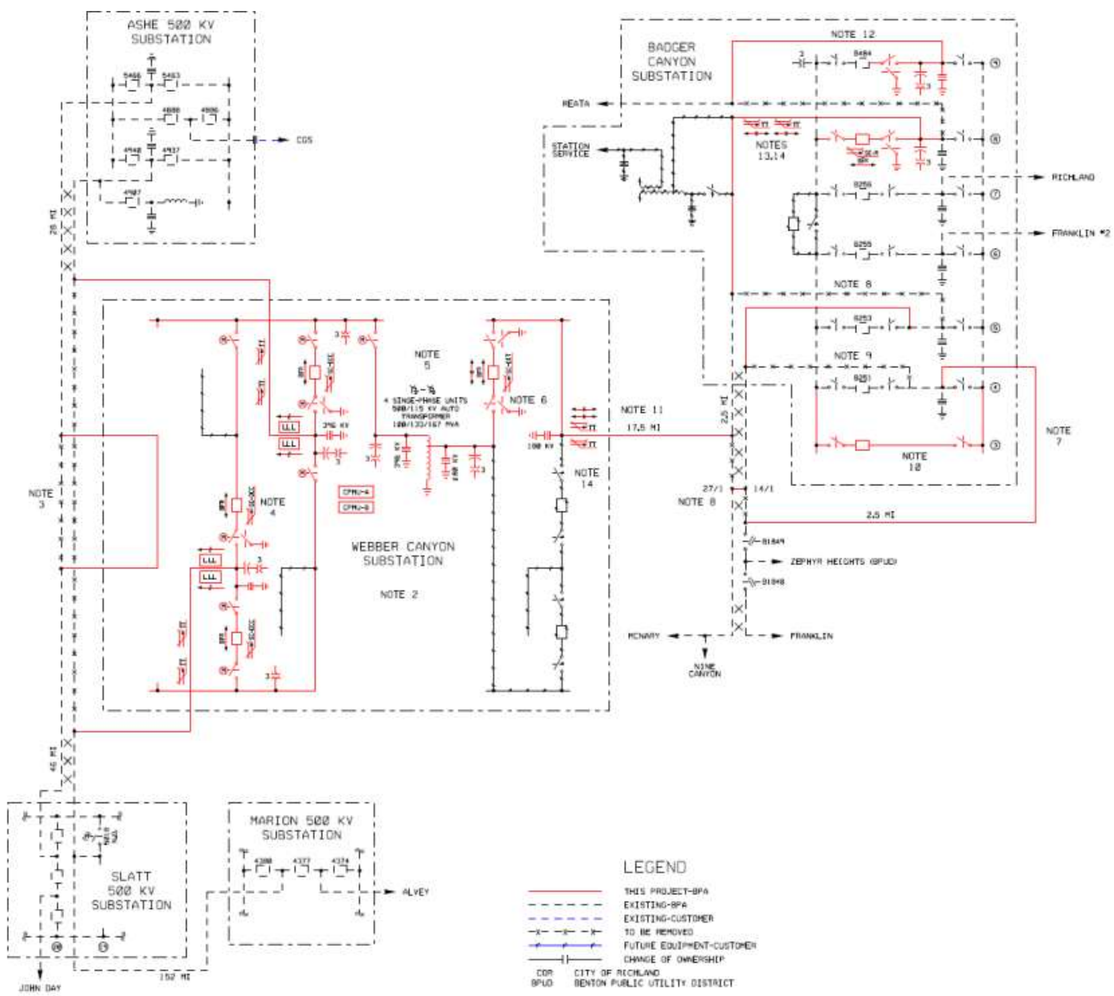
This planned project reinforces the South Tri-Cities Area to address near-term operations and maintenance issues as well as planning reliability issues in the Tri-Cities area in Washington. The area is compliant with planning standards for the loss of any single element. However, loss of two sources to the area may result in substantial loss of load. This hinders the ability to take any transmission facilities in the area out for maintenance since plans must be in place to address the potential loss of a second element.

Two alternative plans to reinforce the area are being scoped:

The Webber Canyon plan of service builds Webber Canyon substation and loops the Ashe-Marion No.2 500 kV line into a 500 kV ring bus configuration. A new Webber Canyon 500/115 kV transformer (four single phase units) connects 20 miles of 115 kV line (built to 230 kV) to Badger Canyon substation.

The East Roza plan of service builds a new East Roza substation and taps the Ashe-Slatt No.1 500 kV line creating a three-terminal 500 k line. A new East Roza 500/115 kV transformer then connects 6 miles of 115 kV line to Red Mountain substation.

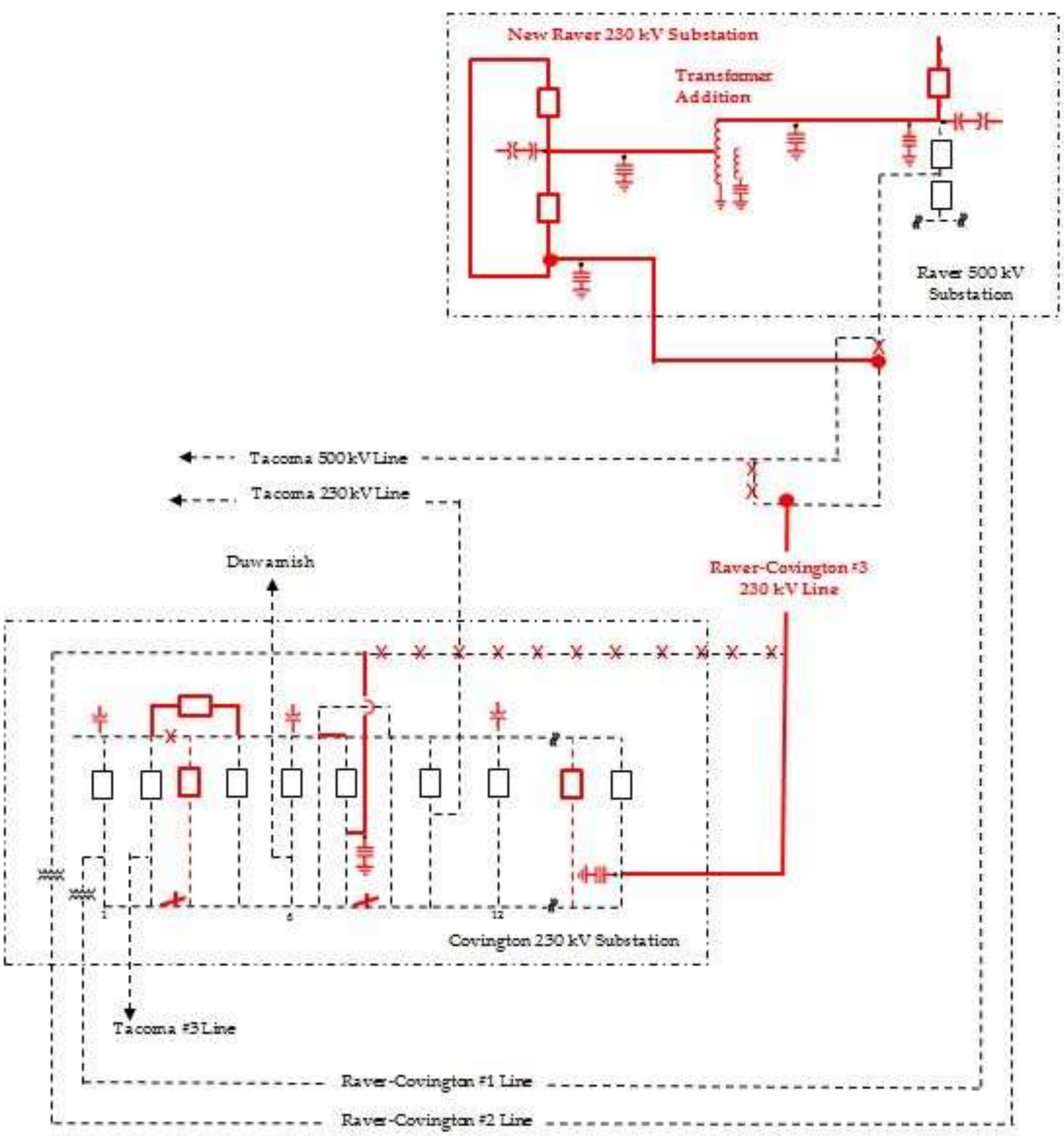
This project is presently in the scoping phase. The estimated project cost and schedule will be refined as the project progresses through scoping.



4.2 Raver 500/230 kV Transformer Addition

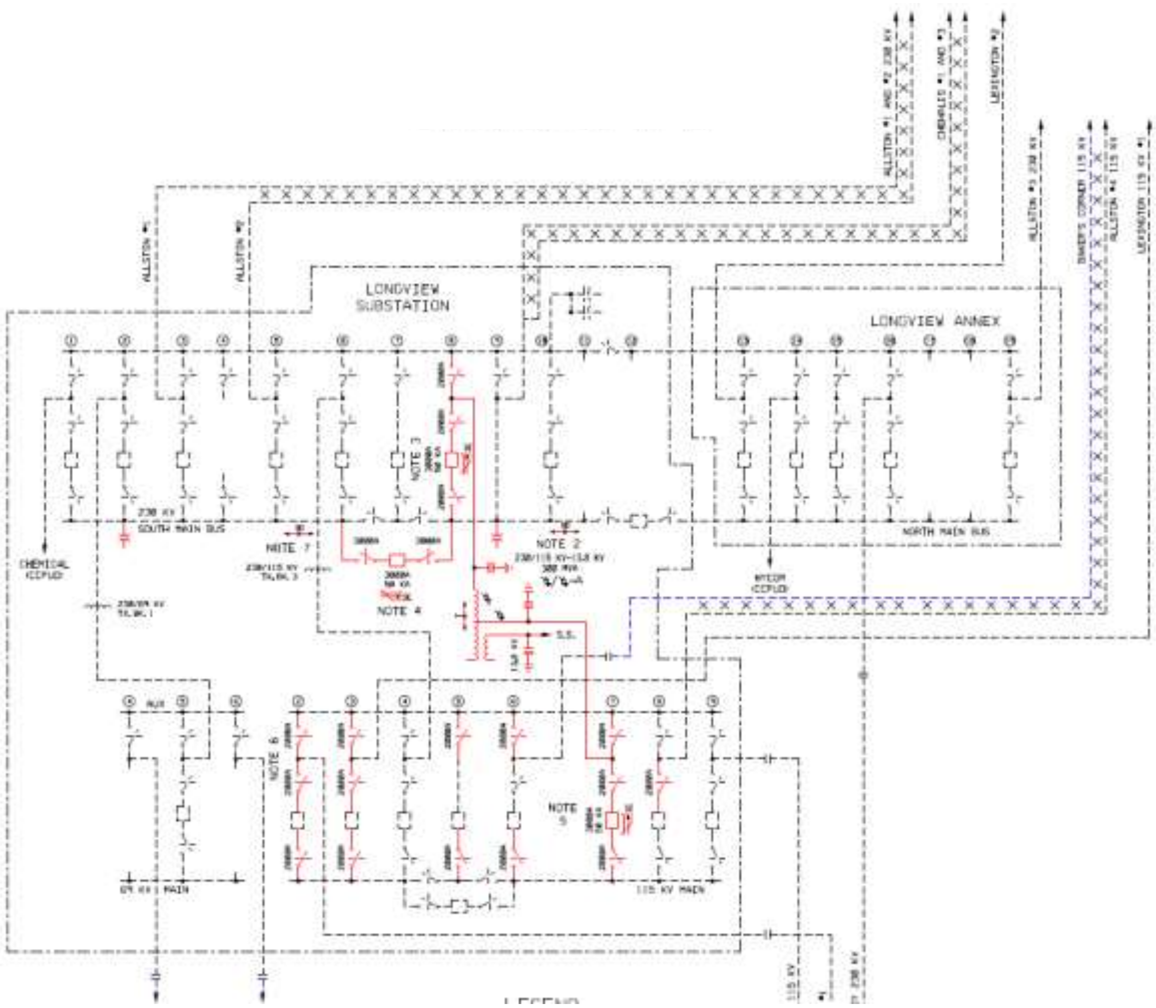
The plan of service is to install a 1300 MVA transformer at Raver substation. A new 230 kV substation will be developed adjacent to the existing 500 kV substation. The high side of the new transformer will terminate at Raver 500 KV. The project will also reconfigure the Tacoma-Raver 500 KV lines by removing jumpers and re-terminating the Tacoma-Raver #2 circuit into Covington 230 KV and Raver 230 KV Substations. The Tacoma-Raver #2 line will be renamed and operated as the Raver-Covington #3 230 KV line. The plan of service also requires reconfiguring the Covington 230 KV bus, adding a new sectionalizing breaker and 2 bus tie breakers. This project is primarily for load service to Tacoma and Covington Substations and has no significant impact to the WECC transmission system. It has been studied as part of a sub-regional Puget Sound Area Study team through Columbia Grid.

The proposed energization date is 2020 and estimated cost is about $72 million. The project is in the construction phase.



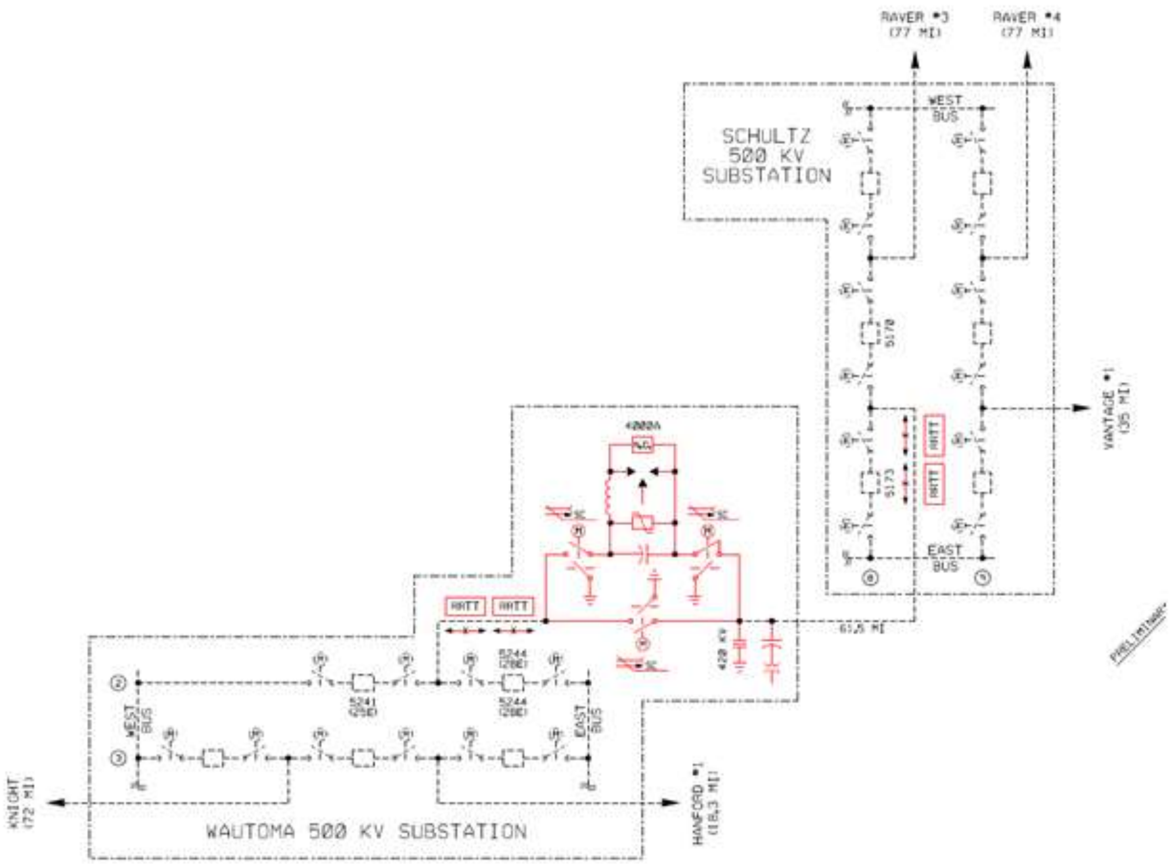
4.3 Longview Area 230/115 kV Transformer Addition

This project installs a second 230/115 kV transformer bank at the Longview Substation in the Longview area. To make room for the new transformer, the existing 230/13.8 kV transformer bank no. 5 will be removed. A new 230 kV bus sectionalizing breaker on the Longview 230 kV main bus section will be added. This project will maintain reliable load service to the Longview area. The Longview Load Service Area covers Cowlitz County. The proposed energization date is 2022 and the estimated cost is about $15 million. This project is in the design phase.



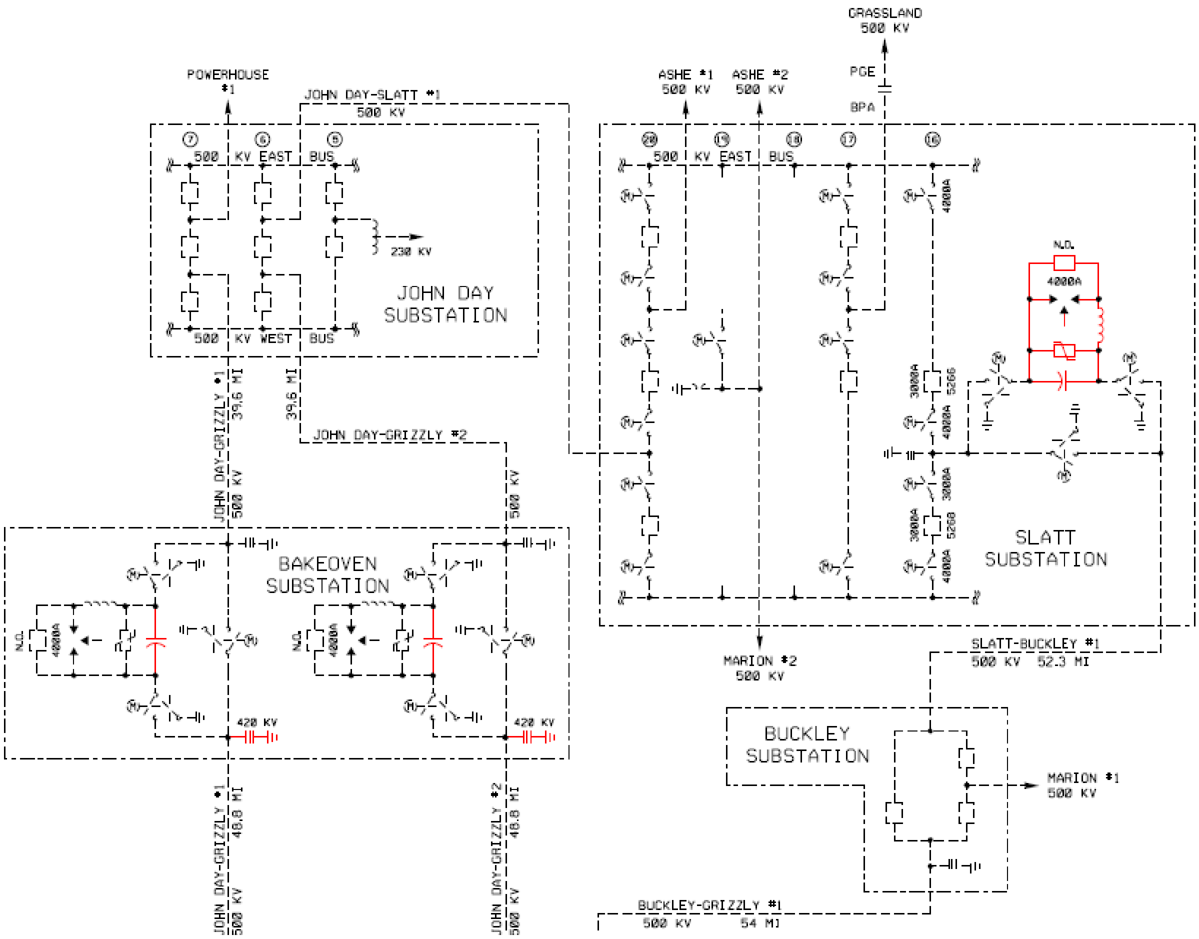
4.4 Schultz-Wautoma 500 kV Series Capacitor Addition

This project is necessary to increase South of Allston (SOA) available transfer capability and improve operations and maintenance flexibility for SOA and I-5 paths in the Tri-Cities area. The project will add 1152 Mvar, 24 OHM series capacitor (rated 4000A at 500 kV) on the Schultz-Wautoma line at the Wautoma substation. The proposed energization date is 2022 and the estimated costs are about $22.3 million. The cost estimate is early in the process and will be refined as the project progresses.



4.5 Slatt Series Capacitor Addition and Bakeoven Series Capacitor Optimization

This project involves adding a new 14 ohm series capacitor at Slatt Substation in the Slatt- Buckley 500 kV line and upgrading the existing series capacitors at Bakeoven in both John Day – Grizzly No. 1 and No. 2 500 kV lines by reducing the size from 25 ohms to 21.25 ohms. This California-Oregon Intertie (COI) project was initiated in response to large line and load interconnection requests in the Central Oregon area which impact the COI. This project was energization in June 2019 and the bundled project cost is about $13.5 million.



TRANSMISSION PLANNING

5. Transmission Planning Landscape

Transmission Planning's goal is to provide a reliable, flexible, environmentally responsible, and cost effective transmission system. Transmission Planning conducts the planning process in an open, coordinated and transparent manner through a series of open planning meetings that allow anyone to provide input into and comment on the development of the ten-year plan. Transmission Planning also strives to have a regionally coordinated system. For instance, Transmission Planning experts engage in regular meetings with interconnected utilities for information exchange and joint studies, conduct stakeholder meetings, and participate in regional planning. Below are changes in the landscape that Transmission Planning participates in or is impacted by.

5.1 Western Energy Imbalance Market

The Western Energy Imbalance Market (EIM) is a real-time wholesale energy trading market that enables participants anywhere in the west to buy and sell energy when needed. An EIM is intended to provide better generation-load balancing by adjusting generation in much smaller time increments. The benefits of an EIM include economic efficiency or an automated dispatch, savings due to diversity of loads and variable resources in the expanded footprint, and favorable impacts to reliability or operational risk.

Expanding system access to non-ISO members in other states benefits consumers, producers, and other grid operators as the California Independent System Operator (CAISO) leverages the power of geographic diversity to better integrate renewables. Most wind and solar energy resources naturally vary with changes in weather. A larger geographical area makes these changes less pronounced as production increases in one area help to offset reductions in others. In addition to more effectively using excess renewable and existing resources, the ISO automated grid management systems find the most cost efficient power plants to serve demand creating substantial financial benefits.

Source: CAISO

The EIM was launched in 2014 by the CAISO and interest has grown as more utilities join the EIM. Active participants include Balancing Authority of Northern California/SMUD (2019), Idaho Power Company (2018), Powerex (2018), Portland General Electric (2017), Puget Sound Energy (2016), Arizona Public Service (2016), Nevada Energy (2015), and PacifiCorp (2014).

Pending participants are Salt River Project (2020), Seattle City Light (2020), Los Angeles Department of Power & Water (2021), Public Service Company of New Mexico (2021), NorthWestern Energy (2021), Turlock Irrigation District (2021), Avista (2022), Tucson Electric Power (2022) and Tacoma Power (2022).

BPA is currently determining how and under what conditions it could join the EIM, with a potential implementation date of April 2022.

- For more information on BPA's EIM Stakeholder process and meetings please visit: https://www.bpa.gov/Projects/Initiatives/EIM/Pages/Energy-Imbalance-Market.aspx

- For more information on BPA's Grid Modernization Initiative please visit: https://www.bpa.gov/goto/GridModernization

5.2 Northwest Power Plan & Mid-Term Assessment

The Power Council's Seventh Power Plan (Plan) was published in 2016. The purpose of the Plan is to provide recommendations so that regional entities can take specific action to implement the plan focusing on the early years of the 20-year plan. The Seventh Power Plan **Mid-Term Assessment** (Assessment) was final in early 2019. The purpose of the Assessment is to review the region's progress in implementing the Seven Northwest Power Plan.

5.2.1 Seventh Power Plan Recap

As a recap, the Plan expressed energy efficiency takes the lead role in meeting the region's energy needs, followed by demand response and increased use of existing natural gas-fired plants as regional coal plants are retired. The Council's analysis shows that energy efficiency can meet the region's expected load growth, an average increase of 0.5 to 1.0 percent each year through 2035.

The Plan recommends continued improvement in system scheduling and operating procedures across the region's balancing authorities. The region also needs to invest in its transmission system to improve market access for utilities, reduce line losses, and help develop cost-effective renewable generation. The Seventh Plan calls for the region to be prepared to develop significant demand responsive resources by 2021 to meet additional winter peaking capability. The Northwest's power system has historically relied on the hydro system to provide peaking capacity, but under critical water and weather conditions, additional capacity is needed to meet the region's adequacy standard.

An important finding in the Seventh Power Plan is that future electricity needs can no longer be adequately addressed by only evaluating average annual energy requirements. Planning for capacity to meet peak load and flexibility to provide within-hour, load-following, and regulation services will also need to be considered.

5.2.2 Mid-Term Assessment

The Assessment describes some circumstances that have changed since the Seventh Plan was published. Generally, the Assessment states the strategy described in the plan remains sound. One of the Assessment's major findings shows progress towards identifying barriers to demand response, and while this is the case, the region has yet to make substantial progress towards the recommended 600 megawatts of incremental demand response as laid out in the Plan. Key aspects of the Assessment show there have been additional retirements of coal generation and a larger-than-expected reduction in the cost of wind and solar generating technologies. Another essential point is the market for natural gas and electric prices are low.

Gas, wind and solar plants are displacing coal generation. Finally, the region may have a potential shortfall in resources needed to meet electricity demand after 2020 when the Boardman and Centralia 1 coal plants retire.

5.2.3 Mid-Term Assessment Highlights

Some items in the Assessment are of particular interest to transmission planning efforts such as additions and retirements of generation resources, announced planned coal retirements, the anticipated cumulative renewable resource additions, and regional demand response infrastructure. Several noteworthy diagrams gleaned from the Assessment are shown below. More information can be obtained by downloading the full report on the Northwest Power and Conservation Council web site.

In Section 2 – Action Plan Implementation Progress, it discusses that since the release of the Seventh Plan, all the regional investor-owned utilities have released Integrated Resource Plans (IRP) that shows a new or continuing need for demand response (DR). Additionally, Bonneville's recent Resource Program found DR to be a priority resource in the summer. The Assessment determines it is unlikely the region will achieve the 600 MW of incremental demand response recommended in the Seventh Plan, but will continue to engage in committee work and explore ways to expand demand response infrastructure. The chart below shows contributions to demand response. The start date in the chart below indicates when the entity will anticipate needing demand response.

Source: Council's Mid-Term Assessment – Expand Regional Demand Response Infrastructure

Utility	Amount DR (MW)	Start Date
BPA	131 (summer)*	2020
Puget Sound Energy	103 (winter)	2023
Portland General	69 (summer), 77 (winter)	2021
PacifiCorp	500 (summer)	Continuing
Avista	44 (winter)	2025
Idaho Power	390 (summer)	Continuing
Northwestern Energy	TBD – winter	TBD

* Portfolios 2 and 3

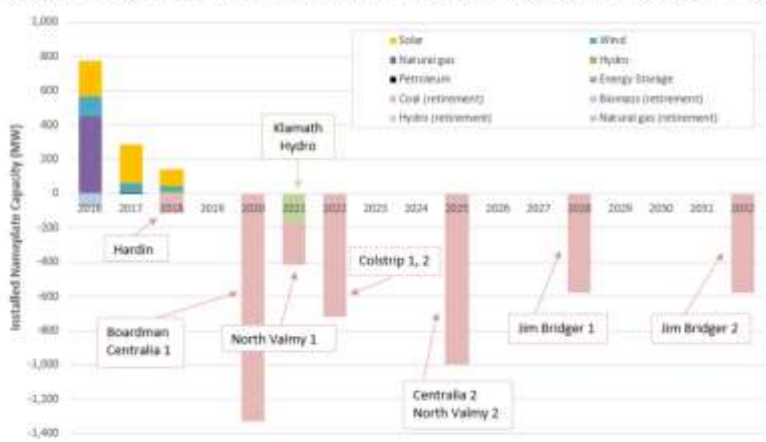
In Section 4 – Conservation, the Seventh Power Plan called on the region to acquire 1,400 average megawatts of energy efficiency over the six-year action plan period (2016-2021). The Plan provided two-year milestones over the six-year period to reach this goal. Consistent with the findings in the Plan, the region is seeing the capacity value of energy efficiency. Energy Planners and efficiency program operators have begun to take the capacity contribution of energy efficiency into account. Many programs are now considering capacity value or are trying to determine how to incorporate the value into their energy-efficiency programs. Also, the Assessment mentions that Bonneville and the Energy Trust of Oregon are engaging in end-use load research to better understand the impact on capacity.

In Section 5 – Demand Response, the Power Council formed a Demand Response Advisory Committee (DRAC) in 2016 to define demand response, provide data on planning and existing demand response program, and highlight key barriers to demand response implementation. Most of region's investor-owned utilities and some public utilities incorporate demand response into their resource planning. Some of the utilities plan to continue their existing demand response program. Other utilities that do not have large-scale demand response programs find a need for demand response in the next five to ten years. The DRAC spent a significant amount of time discussing barriers to demand response. Bonneville contracted a study to explore the barriers. The conclusion is that economic and market barriers are the most significant barriers to adopting demand response. Without a capacity market, it is difficult for many to justify a demand-response investment. Other barriers include regulatory, infrastructure, organizational, and customer understand. The DRAC will explore ways to mitigate the barriers.

In Section 6 – Generating Resources, is a discussion of resource acquisitions and retirements. The following four charts are gleaned from the Assessment. The first two charts show the announced planned coal retirements in the Pacific Northwest. The third chart shows the net balance of coal retirements and anticipated new capacity addition in megawatts. The fourth chart shows the anticipated cumulative renewable resource additions. This information is useful to Bonneville transmission planners as it is necessary to take into account the impacts of the changing mix of resources and power flow in a study area when planning for transmission expansions.

Source: Council's Mid-Term Assessment

Figure 6 - 1: Additions and retirements (including announcements) since the Seventh Plan



* Uncertainty remains regarding the future of Hardin; While Idaho Power is ending its participation in North Valmy 1 in 2019, according to NV Energy it will remain in operation until end of year 2021

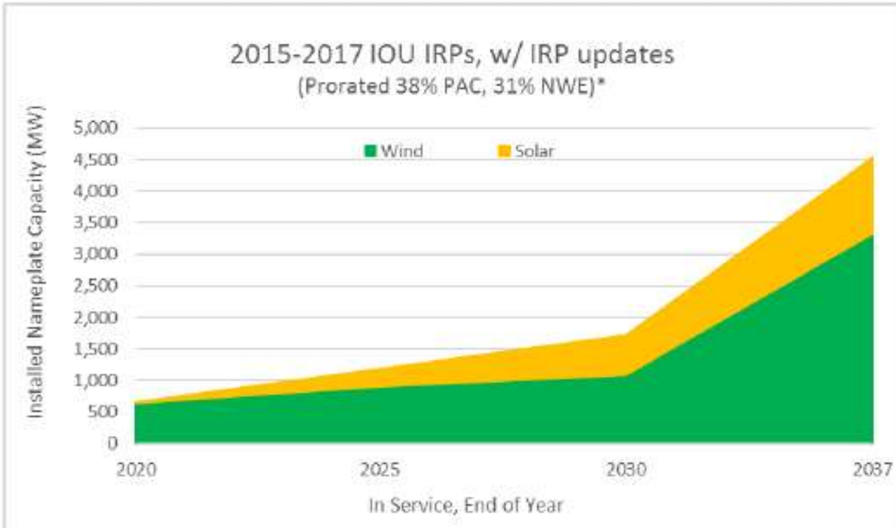
Table 6 - 5: Announced Planned Coal Retirements in the Pacific Northwest*

Plant	Retirement Date	Capacity & Operating Year	Location	Ownership
J.E. Corette	2015	173 MW (1968)	MT	PPL Montana
Hardin	2018	116 MW (2006)	MT	Rocky Mountain Power[1]
North Valmy 1 North Valmy 2	2021[2] 2025	254 MW (1981) 268 MW (1985)	NV	Idaho Power, Sierra Pacific Power (50/50)
Boardman	2020	600 MW (1980)	OR	Portland General Electric, Idaho Power (90/10)
Centralia 1 Centralia 2	2020 2025	670 MW (1971) 670 MW (1971)	WA	TransAlta
Colstrip 1 Colstrip 2	2022	360 MW (1975) 360 MW (1976)	MT	Puget Sound Energy, Talen Energy (50/50)
Jim Bridger 1 Jim Bridger 2[3]	2028 2032	578 MW (1974) 578 MW (1975)	WY	PacifiCorp (2/3)[4], Idaho Power (1/3)
Regional Utility Total		**1,899 MW**		
Regional Total (incl. IPPs)		**3,772 MW**		

[1] Not related to PacifiCorp
[2] Idaho Power will end its participation in 2019, NV Energy to retire unit end of year 2021 per 2019 IRP
[3] Per PacifiCorp's 2017 IRP Update
[4] Regional total includes only PacifiCorp's load to the region (38%)

* For detailed project information, please see the Council's generating resources project database

Figure 6 - 3: Anticipated Cumulative Renewable Resource Additions



* PacifiCorp and NorthWestern Energy's percentage of load serving the region

Table 6 - 6: Net Balance of Coal Retirements and Anticipated New Capacity Additions In MW

All numbers in units of MW	2018 thru 2020	2021 thru 2025	2026 thru 2030	2031 thru 2037	Cumulative 2018-2037
Anticipated Additions	17	379	1,237	2,155	**3,788**
Anticipated Coal Retirements (prorated to reflect % serving Northwest)	(1,270)	(981)	(1,010)	(339)	**(3,600)**
Net Balance Over Period	(1,253)	(602)	227	1,816	**188**

* Note: J.E. Corette is not included in this table because it retired in 2015. This table shows 2018-2037.

5.3 PNUCC Northwest Regional Forecast

The Pacific Northwest Utilities Conference Committee (PNUCC) produces a forecast that serves as a gauge for how much power will be needed and how utilities are meeting those needs. It also signals how utilities are adapting their long-term resource plans to address uncertainties, including new and changing state and federal environmental policies, changes in customer preferences, and other external impacts. The *2019 Northwest Regional Forecast,* released in April 2019 for years 2020-2029, states that with a changing and somewhat chaotic economic, political, technological and social environment, the utility landscape continues to change and evolve. Key trends include northwest utilities achieving carbon-reduction goals, while policymakers are aggressively enacting decarbonization legislation; utility planners are focused on summer and winter peak capacity needs; adequate reliable power is needed as coal plants retire; construction of new wind and other renewable resources cannot fully offset the loss of generation from coal plants retirements; and large-scale battery technology is being explored. Highlights of the report are shown below.

5.3.1 Coal Retirements

Eight coal-fired plants that serve the region are expected to retire causing a loss of about 3,600 megawatts of dispatchable generation. The committed and planned new generation for the next five years is renewable projects. About 950 megawatts of natural gas-fired generation are expected between 2025 and 2028. Utilities continued to pursue energy-efficiency along with demand side-management programs designed to reduce energy use during peak periods. This combination of effects is presenting the region with reliability challenges. Northwest utilities have reliable, low-carbon resources where hydroelectric power is the cornerstone of the Northwest's resource portfolio. Our region's reliance on hydropower means the average carbon footprint is less than half of the rest of the nation. Figure 1 shows the Northwest planned coal unit retirements and Figure 2 shows the Northwest generating resource mix.

Source: *2019 Northwest Regional Forecast*

Figure 1: Northwest Planned Coal Unit Retirements

Project	Nameplate MW	Schedule
Valmy Unit 1	254	End of 2019
Centralia Unit 1	670	End of 2020
Boardman	585	End of 2020
Colstrip Unit 1 & 2	660	July 2022
Centralia Unit 2	670	End of 2025
Valmy Unit 2	267	End of 2025
Jim Bridger 2	540	End of 2028
Total	3,646 MW	

Figure 2: Northwest Generating Resources

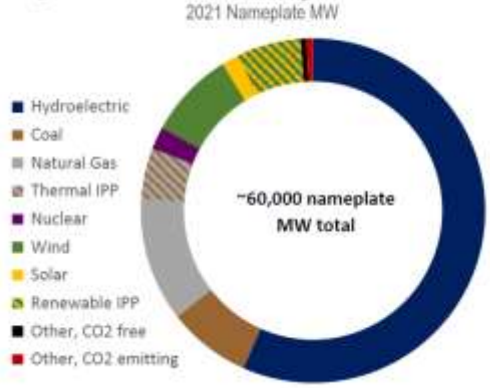


Figure 4: Summer Growth Outpacing Winter

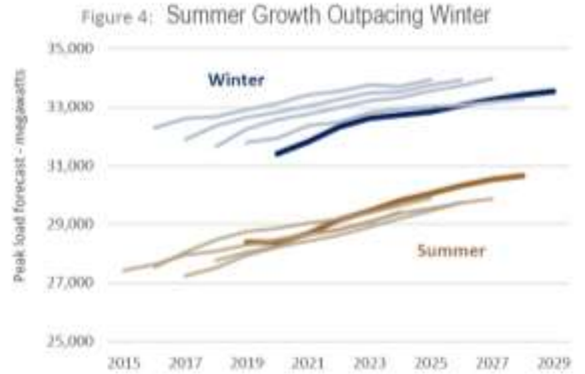
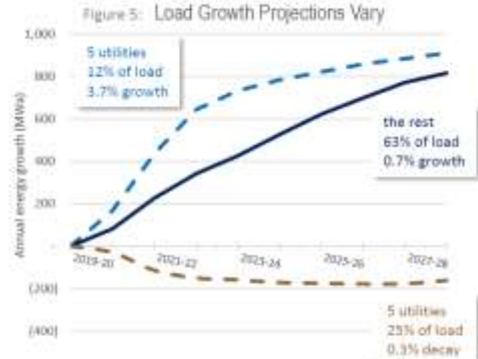


Figure 5: Load Growth Projections Vary



5.3.2 Peak Demand

Summer peak demand for electricity continues to stay on track – many factors contribute to this including increased air conditioning. Whereas the winter peak demand has slipped year over year – likely due to energy efficiency, use of natural gas for heating, lost industrial load and other factors. (Figure 4.)

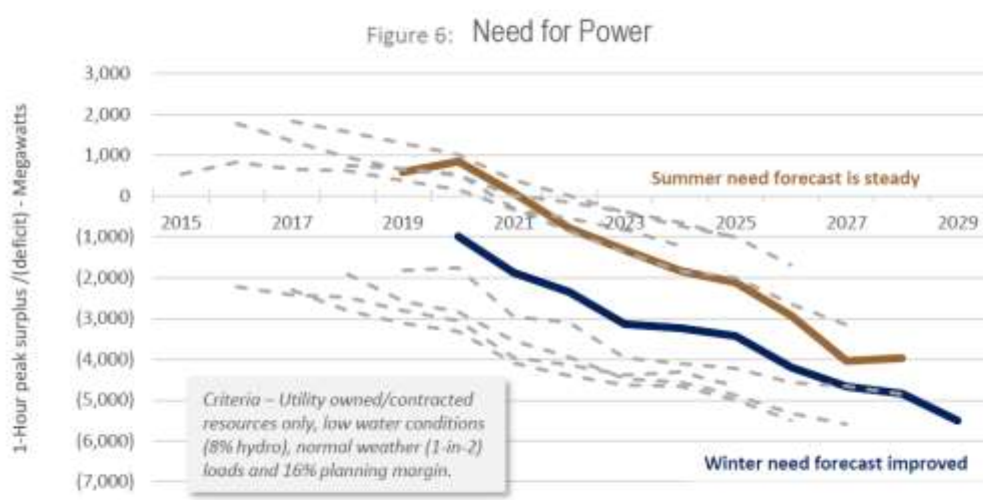
5.3.3 Regional Growth

The annual average load growth for the region is less than one percent over the ten-year horizon. Although forecasted average load growth is flat, some areas experience more robust load growth. Figure 5 above shows demand for electricity for five utilities is growing at an average rate of 3.7 percent per year, while five other utilities are anticipating declining loading on average of 0.3 percent per year. The remaining region's utilities are expecting to grow on average at 0.7 percent annually.

5.3.4 Summer and Winter Peak Needs

PNUCC's forecast states the Northwest has adequate generation to meet customer demand during most times of the year. Given the indication of the forecast horizon, Northwest resource adequacy suggests winter and summer peak deficits will growth through time if no action is taken. Although, the winter peak picture has improved, in part due to the loss of large industrial load, (which can be seen in the upward shift of the blue line in the Figure 6 below), winter peak needs still exists. The summer peak need is also gaining traction. Planning projections continue to indicate that within the forecast horizon, summer-peak requirements will outpace utilities' firm generation, challenging utility planner to consider actions to address both winter and summer peak capacity needs. The forthcoming coal retirements underscore this trend. PNUCC emphasizes, "[W]e cannot look at the Northwest utilities' load/resource balance picture in isolation. Northwest utilities have leaned on better than low hydro generation, power from independent power producers, and imports from outside the region to ease adequacy concerns. Looking ahead, those same opportunities may not exist."

Source: *2019 Northwest Regional Forecast*



5.4 BPA White Book Loads and Resources

The Pacific Northwest Loads and Resources Study (a.k.a. BPA White Book) is BPA's latest projection of the Pacific Northwest regional retail loads, contract obligations, contract purchases, and resource capabilities. The BPA White Book, which is a snapshot of conditions, documents the loads and resources for the federal system and the Pacific Northwest region loads and resources for a ten-year period. BPA's White Book provides estimates of energy and capacity sufficiency and deficiency periods for both the federal system and Pacific Northwest (PNW) regional loads. The White Book is primarily a planning tool and includes two distinct studies: Federal System Analysis and the PNW Regional Analysis.

The 2018 White Book (published April 2019) contains the analysis of the Federal system and the PNW region loads and resources. BPA's Federal System Analysis presents the federal system load and resource balance, by comparing expected loads and contract obligations to resources and contract purchases. In a similar fashion, BPA's PNW regional analysis calculates the regions load and resource balance, by comparing the regions expected total retails loads and contract obligations to the available resources and contract purchases. A brief summary of the sufficiency/deficit outcomes for energy and capacity is provided below.

5.4.1 Federal System Analysis

Energy

Annual energy under critical water conditions is project to have small energy surpluses in the first year of the study (79 aMW), with annual energy deficits (-438 aMW) over the balance of the study period. Under average water conditions, the Federal system is projected to have annual energy surpluses through the study period.

Capacity

Capacity under critical water conditions is projected to have deficits over the study period ranging from -969 MW to -1,406 MW. Under average water conditions, the system is projected to have surpluses over the study period.

5.4.2 Pacific Northwest Regional Analysis

Energy

Annual energy under critical water conditions is project to have surpluses as large as 4,058 aMW in 2020, slowly decreasing to 403 aMW by 2029. Under average water conditions, the region would see even larger energy surpluses over the study horizon.

Capacity

Capacity under critical water conditions is projected to have deficits over the study period ranging from -246 MW to -4,891 MW. Under average water conditions, the region would have capacity surpluses through the final year of the study.

5.5 State’s Renewable Portfolio Standard

A Renewable Portfolio Standard (RPS) is a regulatory mandate to increase production of energy from renewable sources such as wind, solar, biomass and other alternatives to fossil and nuclear electric generation. States created these standards to diversify their energy resources, promote domestic energy production and reduce emissions. This RPS mechanism places an obligation on regulated utilities to produce a specified fraction of electricity from renewable energy sources. Standards are typically measured by the percentage of retail electric sales. Below are general requirements by select states.

- California’s requirement is 44 percent by 2024, 52 percent by 2027, and 60 percent by 2020 for investor-owned and municipal utilities. Finally requiring 100 percent clean energy by 2045.
- Washington’s requirement is 15 percent by 2020 for investor-owned utilities and retail suppliers.
- Oregon’s requirement is 25 percent by 2025 and 50 percent by 2040 for utilities with 3 percent or more of the state’s load; 10 percent by 2025 for utilities with 1.5-3 percent of the state’s load; and 5 percent by 2025 for utilities with less than 1.5 percent of the state’s load.
- Montana’s requirement is 15 percent by 2015.
- Idaho and Wyoming have no standard.

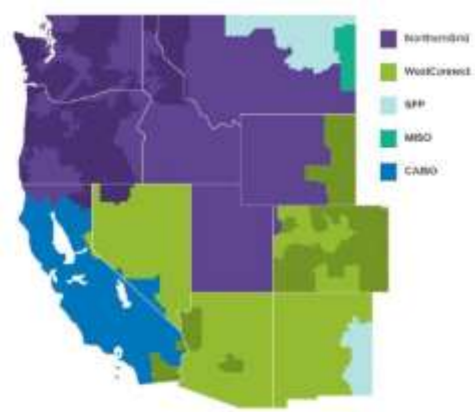
5.6 Northwest Power Pool

The Northwest Power Pool (NWPP) is fundamentally a reserve sharing group among its members. Membership is a voluntary organization comprised of major generating utilities serving the Northwestern U.S., British Columbia and Alberta. Smaller, principally non-generating utilities in the region participate indirectly through the member system with which they are interconnected. The NWPP provides the benefits of coordinated operations. NWPP activities are largely determined by major committees – the Operating Committee, the PNCA Coordinating Group, the Reserve Sharing Group Committee, and the Transmission Planning Committee.

In 2019 NWPP embarked on a mission, coordinating activities relating to a comprehensive review of resource capacity adequacy in the NWPP region. Adequacy concerns were recently demonstrated on March 2019 when the west experienced extreme energy pricing throughout the entire interconnection. As part of their comprehensive review, they held a meeting that resulted in the creation of two teams: The first team was tasked with recruiting regional executives to serve as an advisory group providing direction and oversight to a proposed capacity adequacy assessment forum. The second team is tasked with developing a one page description defining the scope of a limited work product comparing and contrasting several capacity adequacy studies that have been completed to date.

On October 2, 2019 the Northwest Power Pool, with the support of participating entities, will explore working solutions to address the growing Northwest resource adequacy issue. In Episode 1 of their Resource Adequacy docuseries, John Fazio, Senior Systems Analyst with NWPCC states, the “Resource adequacy assessment every year is an early warning to make sure that resources are keeping pace with demand. It’s just a warning…an indication of whether we are starting to fall behind or whether we are still okay.” In Episode 2 Therese Hampton Executive Director of PGP states, “The reason resource adequacy is so important is because you need that lead time to put the generation resources, transmission, the fuel, all that in place. If you get into a situation where you do not have enough capability, you have very limited options.” According to the information on NWPP there is more information to come on resource adequacy.

5.7 NorthernGrid Transmission Group



The NorthernGrid is a new regional planning organization (RPO). The new RPO is intended to facilitate compliance with FERC requirements (including Order Nos. 890 and 1000) for those utilities that are required or elected to comply with such requirements, including cost allocation, when applicable. Participants include Bonneville, investor-owned and consumer-owned utilities in California, Idaho, Montana, Oregon, Utah, Washington and Wyoming. The targeted start date for implementation is January 1, 2020.

One larger planning region will meet the region's transmission planning needs and compliance obligations as it is currently happening with two regions. This larger transmission planning footprint of ColumbiaGrid and NTTG will continue coordination and collaboration as it has been done, but within one RPO. The regional planning principles include transmission planning in a coordinated and transparent manner. The value of the NorthernGrid include a common set of data and assumptions, more opportunities to identify regional transmission projects, single stakeholder forum, and eliminates duplicative processes.

Participants and Formation:
Active participants include almost all members of ColumbiaGrid and NTTG

COLUMBIAGRID
Avista
BPA
Chelan PUD
Puget Sound
Seattle City Light
Snohomish PUD
Grant PUD*
Tacoma Power*

+

NTTG
Deseret
Idaho Powr
Enbridge/MATL
NorthWesternEnergy
PacifiCorp
Portland General Electric
Utah Assoc. Municipal Power System

→ NorthernGrid

Bonneville will be a member and will amend its Attachment K to reflect participation in NorthernGrid. Bonneville's strategic plan alignment (Objective 4a) is to develop and implement policies, pricing and procedures for regional planning and incentivize grid optimization and efficient regional resource development.

5.8 RC West

Bonneville is transitioning reliability coordinator services to RC West from Peak Reliability. BPA has been extensively coordinating with RC West this year, which is operated by the CAISO. A reliability coordinator is the top cop for transmission reliability across a wide geographic area. It is responsible for ensuring that each member operates with a focus on reliability, particularly across one area to the next. The reliability coordinator receives real-time data from the entities within its geographic area and models those systems to ensure the stability and region of the grid. RC West will have about 40 members.

For Bonneville, the transition is part of the grid modernization project undertaken by a large team of employees from across the agency. The team addressed new technological requirements, data integrations, process changes, communication and training to interface with the new reliability coordinator. Beyond the reliability coordinator services, this effort better positions Bonneville to participate in the Western EIM if the agency decides to do so.

This page is intentionally left blank.

6. Transmission Planning Overview

The Transmission Planning organization is responsible for planning BPA's transmission system and providing guidance to BPA's Transmission Services' asset investment strategy. Our core responsibilities include developing expansion plans for system reinforcements to meet transmission system needs for load growth, adequate transfer capability, and requests for generation interconnections, line and load interconnections, and long-term firm transmission service. Below are the highlights of what we do:

- Transmission Planning assesses transmission system performance using North American Electric Reliability Corporation (NERC) reliability standards and Western Electricity Coordinating Council (WECC) criteria and develops a long-range transmission expansion plan to meet the expansion needs of BPA's transmission system. Transmission Planning also develops plans of service, including non-wires solutions, to reinforce load service areas, flow gates and interties. Planning develops project requirements diagrams, obtains cost estimates, and supports development of business cases.

- Transmission Planning coordinates projects through BPA's Transmission Planning Process under OATT Attachment K and through sub-regional planning organizations such as Columbia Grid.

- Transmission Planning performs technical studies for generation and load interconnection requests and other customer requests.

- Transmission Planning supports the Transmission Marketing and Sales organization through available transfer capability calculations. Transmission Planning supports the Transmission Service Requests Study and Expansion Process (TSEP) which includes conducting cluster studies and developing expansion plans to accommodate long-term firm transmission service requests.

- Transmission Planning participates in industry groups and organizations such as NERC, WECC, Federal Energy Regulatory Commission (FERC), Department of Energy (DOE), and regional and sub-regional planning organizations. Transmission Planning represents BPA on issues pertinent to transmission planning through participation in regional and national groups.

- Transmission Planning sponsors, develops and supports Technology Innovation projects within the planning arena.

6.1 Planning Processes

6.1.1 Reliability and Load Service

BPA plans the transmission system to serve expected loads and load growth for at least the next ten years based on forecasts. The forecasted peak loads, plus existing long-term firm transmission service obligations, are used to determine the system reinforcement requirements for reliability. BPA plans the system in accordance with the NERC Planning Standards and WECC Regional Criterion to maintain system reliability. Within the BPA service area, load growth occurs at different rates depending on the specific geographic area. BPA has divided its service area into load service areas grouped by either electrical or geographical proximity. The load areas in the Transmission Needs section are listed roughly in order from largest to smallest, based on total estimated load served in each area.

6.1.2 Transmission Service Requests

Qualified customers may request long-term firm transmission service on BPA's transmission system. This service is requested through Transmission Service Requests (TSR) according to the terms of the BPA OATT. TSRs are one of the drivers for system expansion projects. BPA manages these customer requests for transmission service through Transmission Service Request and Expansion Process (TSEP).

6.1.3 Generator Interconnection Service Requests

Qualified customers may request interconnection to BPA's system for interconnecting new generation. BPA receives Generator Interconnection (GI) Requests according to the Attachment L (Large Generator Interconnection Process) and Attachment N (Small Generator Interconnection Process) of the BPA OATT. The Generator Interconnection projects listed in this T-Plan include projects over 20 MW (Large Generator Projects) which have an executed Large Generator Interconnection Agreement (LGIA).

6.1.4 Line and Load Interconnection Service Requests

Qualified customers may request new points of interconnection on BPA's transmission system. These Line or Load Interconnections (LLI) are typically for new load service or to allow the Customer to build or shift the delivery of service to different points on their system. This service is requested according to BPA's Line and Load Interconnection Procedures Business Practice. Similar to the generator interconnection projects, only larger projects which have an executed construction agreement are included in this T-Plan. The LLI process is very similar to the generation interconnection process.

6.1.5 Power Services and Transmission Planning

BPA is working to ensure that Power Services and Transmission Planning are coordinated in their long-term planning activities, processes and decision-making in a way that enables BPA to meet and deliver on its statutory load-serving obligations to its regional firm power and transmission customers. Developing this plan meets part of the combined planning objective. The decision on future transmission load service policy and products may impact current planning processes and that information will be reflected in future T-Plans.

6.2 Roles and Responsibilities

The role of BPA's Transmission Services is to provide open access transmission service for customers, utilities, generators, and power marketers consistent with applicable regulatory requirements. In fulfilling this role, Transmission Planning is responsible for analyzing the changing load and resource trends and patterns and planning a transmission system that will meet the needs of the Pacific Northwest for the future consistent with our mission and vision. From the planning standpoint, the power system can be viewed from a simplistic standpoint of three basic components.

6.2.1 Loads

The loads tend to be clustered into geographical areas. For planning purposes, Transmission Planning has defined over 20 load areas. Examples include the Portland load area, the Seattle load area, the Spokane load area, etc. In the Transmission Needs section of this T-Plan projected loads are shown for each load service area. Forecasted summer and winter loads in megawatts are shown five and ten years out for each area. A list of potential projects is identified by load service, paths, flow gates and interties in the Transmission Needs section.

6.2.2 Paths

The paths represent the transmission system that moves energy between the loads, generation, and external interconnections described above.

6.2.3 Interties

BPA is part of a western interconnection that includes the whole western United States and Canada. There are four interconnected external areas, British Columbia, Montana, Idaho, and California. Bonneville has high capacity interties that interconnect the loads and resources in the Bonneville service area to loads and resources in these adjacent interconnected areas.

LOAD AREAS

PATHS

INTERTIES

This page is intentionally left blank.

TRANSMISSION PLANNING

7. OATT Attachment K Overview

7.1 Responsibilities

The planning processes described in BPA Open Access Transmission Tariff (OATT) Attachment K are intended to result in plans for the Transmission Provider's Transmission System which is updated annually. This planning process supports the responsibilities of BPA under other provisions of its OATT to provide transmission and interconnection service on its transmission system.

Attachment K describes the process by which BPA intends to coordinate with its transmission customers, neighboring transmission providers, affected state authorities, and other stakeholders. Neither Attachment K, nor the BPA Plan, dictates or establishes which investments identified in a BPA Plan should be made, or how costs of such investments should be recovered. BPA decides which of such identified investments it will make taking into consideration information gathered in the planning process described in Attachment K, and any process required by the National Environmental Policy Act, but retains the discretion to make such decisions in accordance with applicable statutes and policies.

Attachment K describes a planning process that contemplates actions by not only the Transmission Provider and its customers under this OATT, but also others that may not be bound to comply with this Attachment K, such as other transmission providers (and their transmission or interconnection customers), States, Tribes, WECC, sub-regional planning groups, and other stakeholders and Interested Persons.

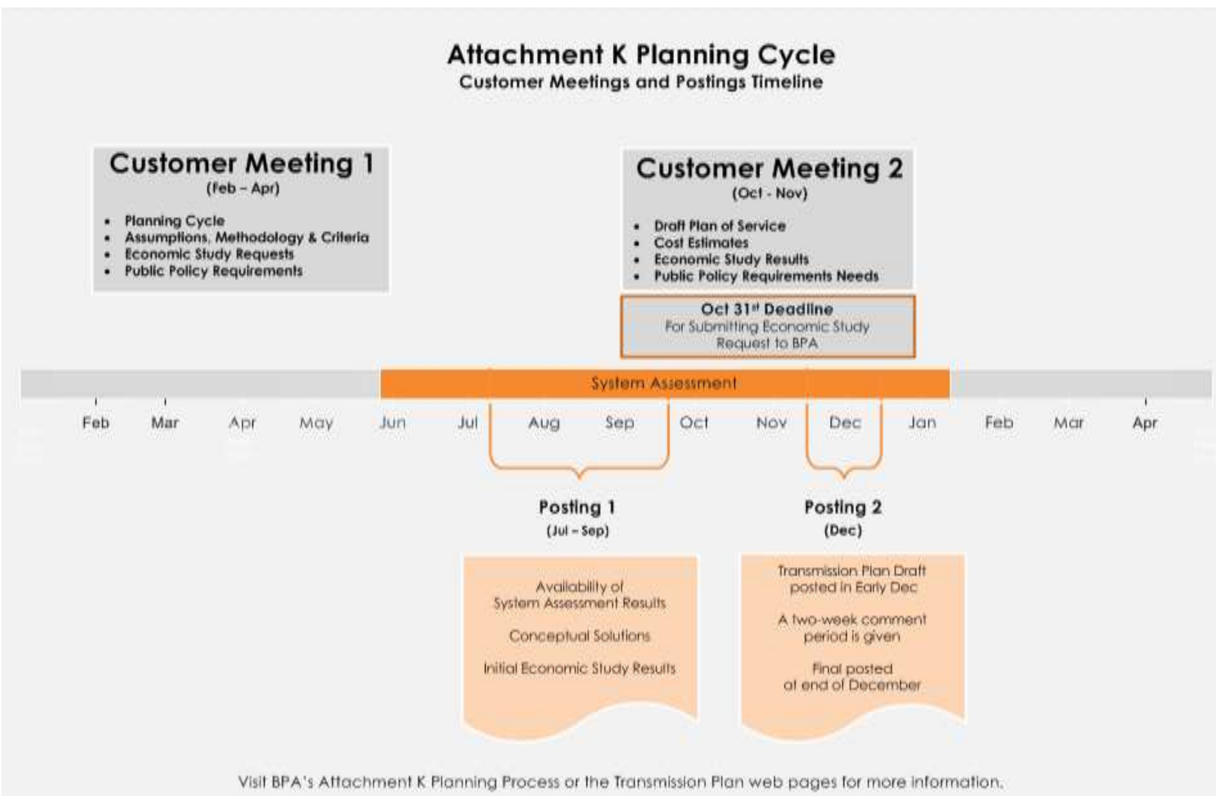
BPA is obligated as specified in Attachment K to participate in planning activities, including providing data and notices of its activities, and soliciting and considering written comments of stakeholders and Interested Persons. However, Attachment K contemplates cooperation and activities by entities that may not be bound by contract or regulation to perform the activities described for them. Failure by any entity or Person other than the Transmission Provider to cooperate or perform as contemplated under this Attachment K, may impede or prevent performance by the Transmission Provider of activities as described in this Attachment K.

BPA uses reasonable efforts to secure the performance of other entities with respect to the planning activities described in Attachment K, but is not obligated for ensuring the cooperation or performance by any other entity described by Attachment K. For example, if and to the extent any Transmission Customer or other entity fails to provide suitable data or other information as required or contemplated by Attachment K, the Transmission Provider cannot effectively include such customer and its needs in the Transmission Provider's planning.

7.2 Planning Cycle

BPA Transmission Services conducts system planning meetings in accordance with its Open Access Transmission Tariff Attachment K. One of the primary objectives outlined under FERC Order 890, Attachment K is the development of a transmission expansion plan that covers a ten-year planning horizon. This plan identifies projected transmission reinforcements based on forecasted load growth, projected firm transmission service commitments, interconnection requests, and system reliability assessments. The objective of the assessment is to test the reliability of the transmission system under a variety of system conditions.

Attachment K is an annual cycle that spans the calendar year - January to December. Below is a diagram depicting the overall Attachment K Planning cycle. The first part of the year area planning is conducted by the Planning Engineers. The engineers use the power flow model and conduct technical studies. Once that process is completed, the next stage is producing the System Assessment Summary Report. The purpose of this report is to document BPA's Annual System Assessment and provide evidence of compliance with the NERC Planning Standard TPL-001-4. The NERC Standard TPL-001-4 requires that BPA conduct an annual assessment to ensure that the BPA transmission system is planned to meet the required performance for the system conditions specified in the Standard. Finally, the Transmission Plan is developed and published by year's end. The purpose of the Transmission Plan is to document the forecast of transmission projects in BPA's service territory for the next ten years. It includes transmission needs identified from the annual reliability system assessment, transmission service and new generation and line and load interconnection requests. At least two public meetings and postings occur during the Attachment K Planning cycle to share transmission planning information with customers and stakeholders.



7.3 Public Meetings and Postings Cycle

Transmission Planning conducts system planning meetings in accordance with Attachment K of the BPA Open Access Transmission Tariff (OATT). These meetings provide customers and interested parties the opportunity to discuss and provide input to the studies and development of the plans of service.

BPA provides information about the Transmission Services Attachment K process including notifications of meetings, results of planning studies, plans of service and other reference information on its web site. To request participation in the Planning Process, complete and email the Participation Request form.

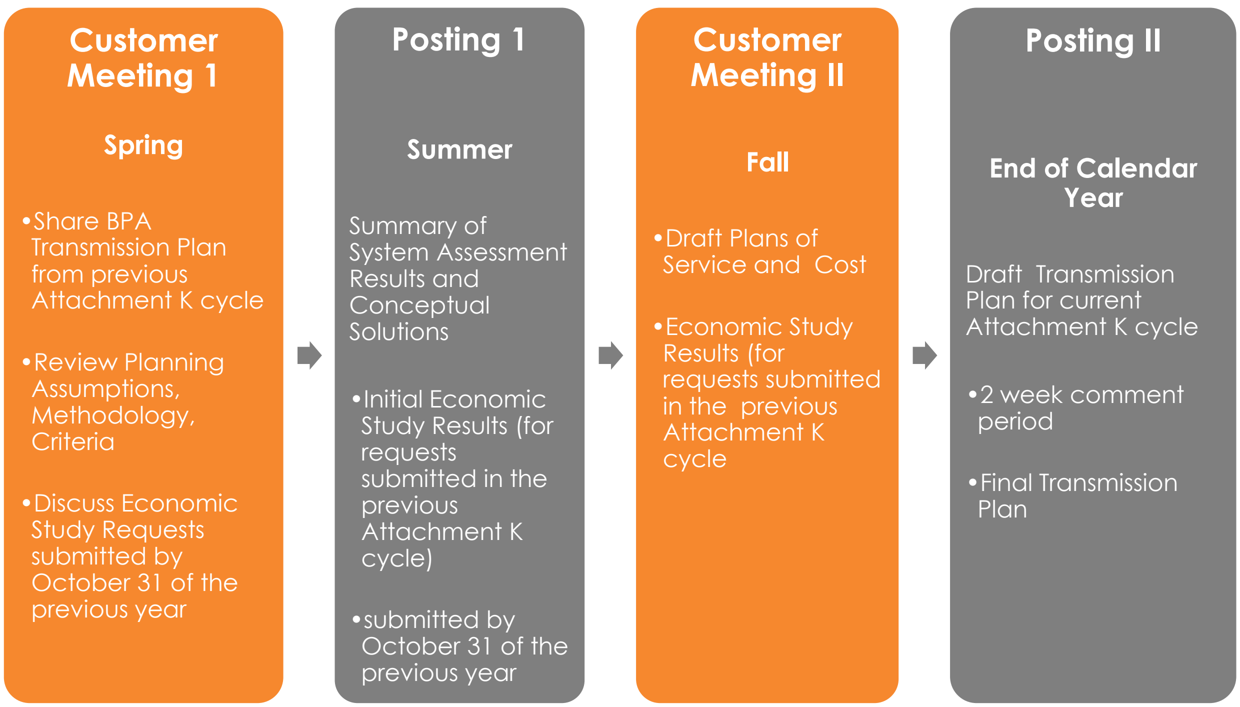


Figure 2 Attachment K Public Meetings and Postings Cycle Diagram

7.3.1 Economic Study Requests

As part of BPA's Attachment K Planning process economic studies may be requested by customers to address congestion issues or the integration of new resources and loads. BPA will complete up to two economic studies per year at its expense. A customer may make a request for an economic study by submitting a request to PlanningEconomicStudyRequest@bpa.gov. A request may be submitted at any time. A request submitted after October 31 will be considered in the next annual prioritization process.

The Transmission Provider will hold a public meeting to review each request that has been received for an Economic Study and to receive input on such requests from interested persons. The Transmission Provider may review Economic Study Requests as part of its regularly scheduled Planning Meetings as outlined in in Attachment K.

After consideration of such review and input, a determination will be made as to whether, and to what extent, a requested Economic Study should be clustered with other Economic Study requests and whether a study is considered a high priority. High-priority economic studies are funded by BPA. Any studies determined not to be high priority will not be performed by BPA, but the BPA may assist in finding an alternate source for performing the studies.

BPA forwards Economic Study requests that require production cost analysis to ColumbiaGrid for review and prioritization. Results of a study are available on its System Planning page of its OASIS web site.

7.3.2 Factors Affecting the Long-Term Transmission Plan

Factors that affect transmission planning include:

- Changes in reliability requirements
- Changes in load forecast and load composition
- Impact of non-wires solutions
- Impacts from energy efficiency and Renewable Portfolio Standards programs
- Other state and national regulations and policy changes
- New or retired generation and transmission facilities

The studies that support this T-Plan reflect current assumptions regarding these factors. Therefore, the plan needs to be updated periodically to capture, among other factors, updated assumptions.

T R A N S M I S S I O N   P L A N N I N G

8. Area Planning & System Assessment

The BPA transmission System Assessment is a comprehensive assessment of BPA's transmission system to ensure compliance with applicable North American Electric Reliability (NERC) Planning Standards and also meet Western Electricity Coordinating Council (WECC) Regional Criterion. WECC is the Regional Reliability Organization for NERC. The NERC Standards TPL-001-4 requires that BPA conduct an annual assessment to ensure that the BPA network is planned such that it can supply projected customer demand and projected firm transmission services over the expected range of forecast system demands. The assessment covers a 10-year planning horizon.

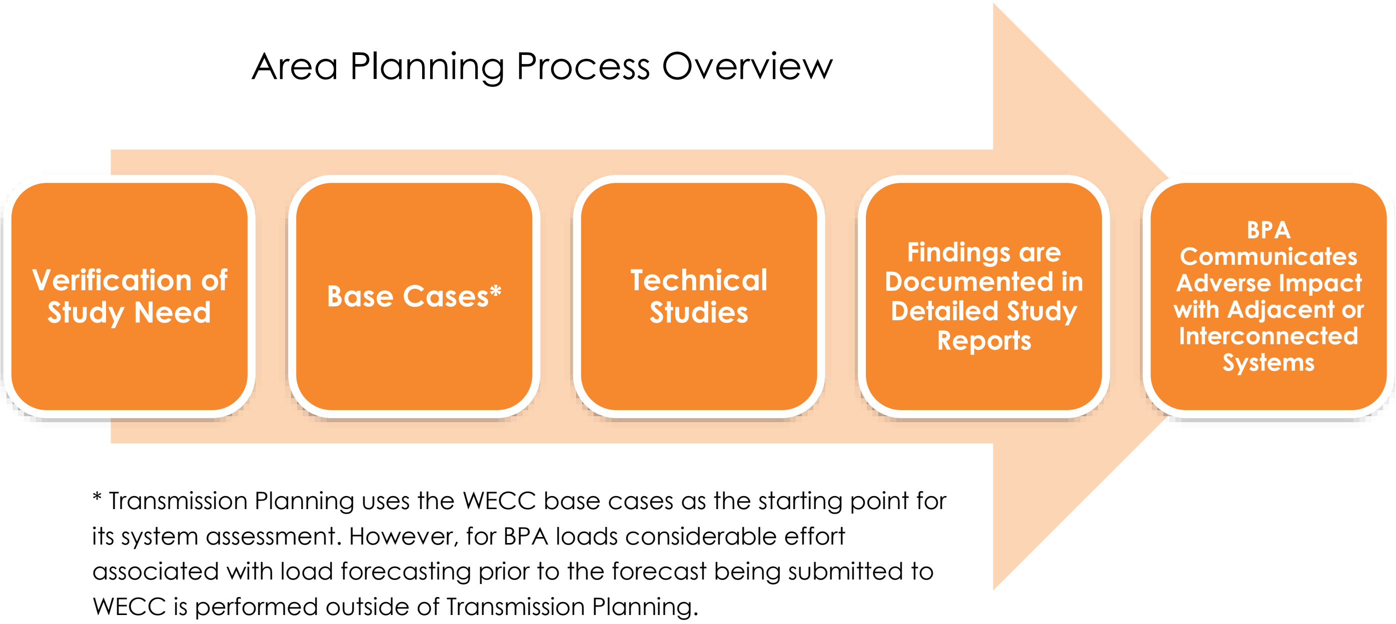


Figure 3 Area Planning Process Overview Diagram

8.1 Area Planning Process

Data collection and modeling occurs at the forefront of the area planning process. Comprehensive computer models are developed to test the reliability of the transmission system under a wide variety of future system conditions. Detailed technical studies are performed to gauge the performance of the transmission system with respect to NERC standards and WECC criteria. These studies eventually result in identifying and testing new transmission reinforcements (corrective action plans), where required. When the detailed technical studies are completed, the results are used to develop the System Assessment Summary Report, and the Summary Report is used as the basis for compliance documentation.

8.1.1 Verification of Study Need

The NERC TPL-001-4 Standard allows system assessments to be based on the results of qualified past studies if they are still valid. A determination is made as to whether a past study shows an adequate transmission plan based on the latest information and is a qualified pasty study, or if a new study is needed for a load area or path. If a new study is required, the result of the assessment process will be a new study report dated for the current year's assessment. If it is determined that a previous study is a qualified past study, the process will result in a verification report documenting the verification checks that support the conclusion that a new study is not required, and reference to the previous study report. At a minimum, a good validation of the load forecast and topology used in studies for each load area should be done annually to verify the timing of corrective action plans.

8.1.2 Base Cases

The purpose of base case development is to provide sufficient base cases that can be used as the starting point for the technical studies that are required by applicable reliability standards such as Transmission Planning Standard TPL-001-4 and others. The NERC TPL-001-4 Standard outlines a minimum of seven cases.

Transmission Planning's assessment includes the creation of study base cases starting with WECC approved base cases from the latest WECC Study Program. Additional base cases are created as necessary to cover other conditions that may need to be studied. If there is not an appropriate WECC approved base case in the latest WECC Study Program, the latest WECC approved base case from the previous WECC Study Program or from the previous year's assessment, whichever is later, are modified to reflect the corresponding year and season. For the years when new cases are not developed, the previous year's cases are updated for any study needs identified.

Transmission Planning works with BPA's Transmission Grid Modeling group to determine which cases are needed for area planning purposes and the annual System Assessment. Considerable work is completed on base cases outside of Transmission Planning and prior to the planning process. WECC produces approved cases. TPMG reviews and updates those approved base cases (known as seed cases) with the latest information available, including updates to topology, ratings, impedances, and loads.

BPA's Load Forecasting and Analysis group is responsible for activities related to forecasting customer load and resource planning including coordinating, managing, overseeing, and directing research into customer loads. These activities result in forecasts of loads and peak amounts for the long-term planning for BPA transmission and power needs.

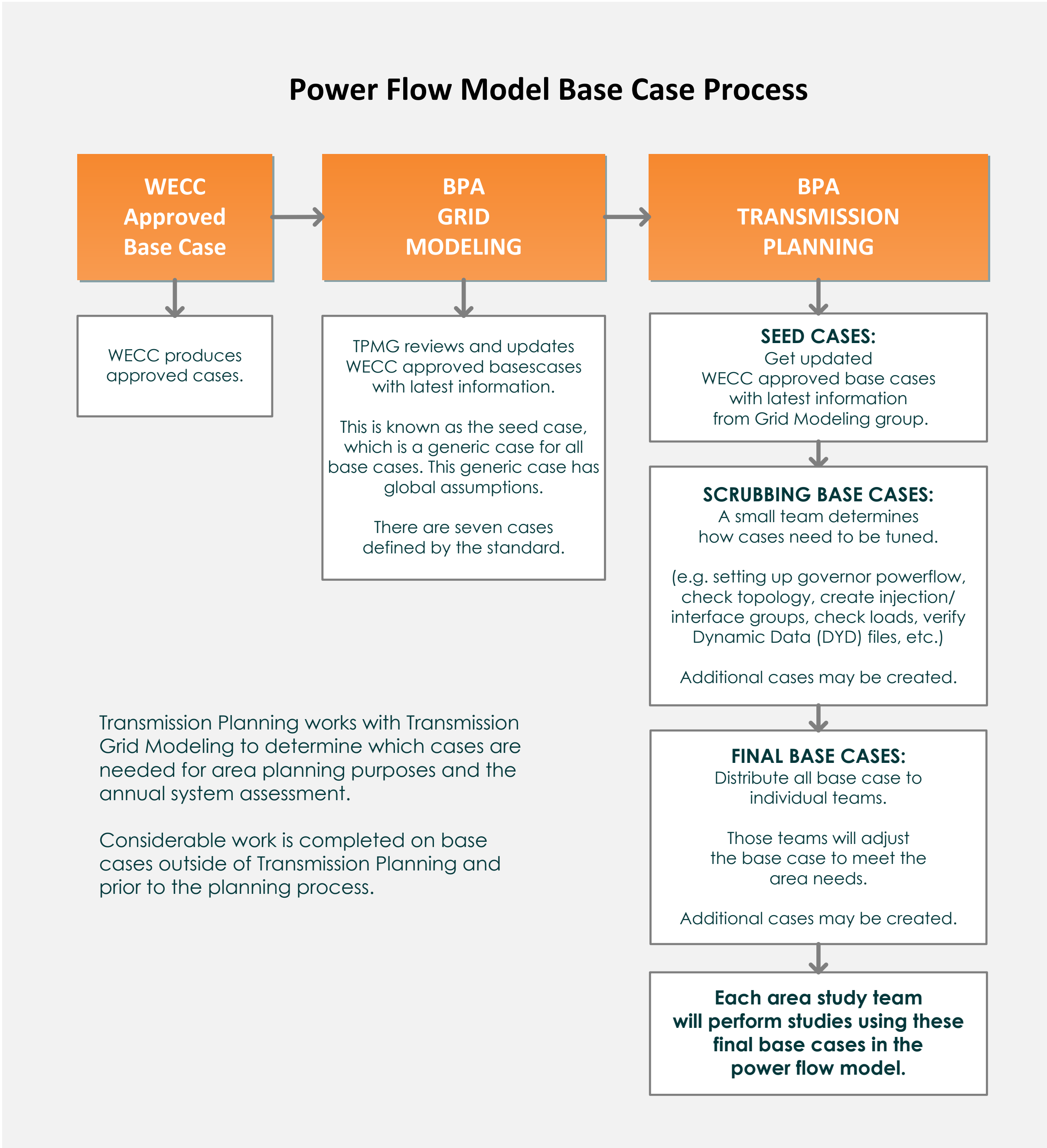


Figure 4 Power Flow Base Case Diagram

8.1.3 Technical Studies

A. Base Case Review and Modification

The base cases are reviewed in more detail and then modified based on individual load areas and paths as follows.

- Stressing paths to appropriate limits for the area of study,
- Verifying generation patterns that affect the area of study,
- Verifying load forecast based on expected conditions and historical data for the load area,
- Verify system additions and/or modifications in the area of study,
- Verify generation additions or changes in the area of study.

B. Studies

The study process ensures all load areas and paths are evaluated to meet all applicable NERC Planning Standards and WECC Criterion. The study process also includes establishment and annual maintenance for standardizing tools, parameters, and assumptions, and continuing improvement of the process.

Short circuit analysis is conducted in BPA's High Voltage Engineering group on an annual basis. Transmission Planning provides assumptions to the High Voltage group of projects to include in the analysis for the next five years. Results of the short circuit analysis and any corrective action plans that result from that study (such as circuit breaker replacements) are included in the System Assessment.

Below is a list of the different types of analysis Transmission Planning performs in the System Assessment:

- Steady State (Power Flow) Contingency Analysis
- Voltage Stability Analysis (PV and QV studies)
- Transient Stability Analysis
- Short Circuit Analysis (performed by BPA High Voltage Engineering group)

C. Corrective Action Plans

If transmission system performance is not adequate to meet NERC and WECC performance requirements, the study process includes the development of corrective action plans as required. These plans consider non-wire solutions, remedial action schemes, operating procedures or system additions/upgrades. The corrective action plans are studied to ensure they provide adequate system performance. If there are multiple alternatives, the best overall plan is recommended. If a non-wires solution is identified it will be coordinated with non-wires team for feasibility of the solutions.

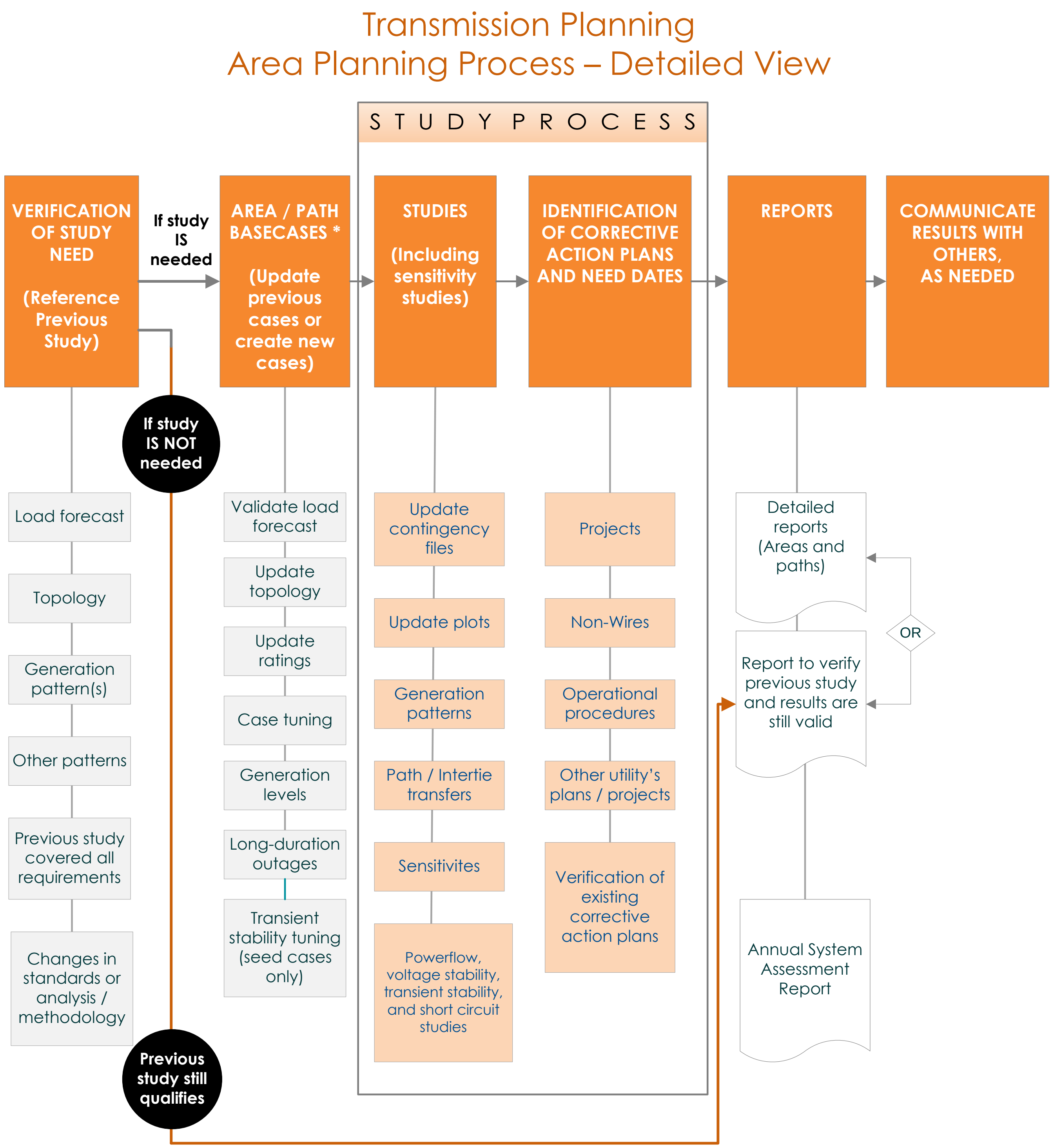
8.1.4 Technical Study Findings are Documented in Detailed Study Reports

After the study process is complete the findings are documented in detailed are and path study reports. In the event that a previous year's detailed report is still valid, a validation report will be completed. This type of report includes the verification checks that support the conclusion that a new study is not required, and reference to the previous study report.

8.1.5 BPA Communicates System Assessment Results

After the technical studies are completed and detailed reports are finalized the results are shared with adjacent Transmission Planners (TPs) and Planning Coordinators (PCs). These are generally the TPs and PCs which are adjacent to or interconnected with the particular study area or path. If those TPs and PCs have systems adjacent to several BPA areas or paths, the respective planners for those areas and paths coordinate with regards to communicating the assessment results (e.g. sharing a single report or multiple reports, having a joint meeting with affected utilities, or several individual meetings, etc.).

For those TPs and PCs where the assessment results show BPA has an impact on the adjacent system or the adjacent utility has an adverse impact on BPA's system, each area or path planner needs to resolve the issues with the adjacent TP and/or PC and document all communication and resolution. This can include face-to-face meetings to provide more detailed supporting documentation to the other utility in addition to the initial assessment results or perform joint studies to resolve common issues.



* Seed base case development process is done in alternate years.

Figure 5 Area Planning Process Diagram

8.2 Planning Criteria

BPA operates under NERC's mandatory and enforceable reliability standards. BPA adheres to these mandatory standards when planning, operating, and maintaining its transmission system. Specifically, NERC's Standard TPL-001-4 which is referred to as the Transmission System Planning Performance Requirements is applicable to Transmission Planning. The purpose of the TPL standard is to establish transmission system planning performance requirements within the planning horizon to develop a bulk electric system that will operate reliably over a broad spectrum of system conditions and following a wide range of potential contingencies.

BPA also plans the transmission system to meet the WECC system performance criteria where applicable. The System Performance Regional Criterion adopted by the WECC establishes technical criteria for acceptable impacts that disturbances can have on the Transmission system.

BPA has also developed a Reliability Criteria for system planning. The purpose of BPA's Reliability Criteria for System Planning is to provide guidance to supplement the NERC and WECC Transmission Planning Performance Requirements, and provide a guideline for making assumptions when planning the transmission system. The BPA reliability criteria also provides guidance where sensitivity studies are specified within the NERC planning standards. These criteria are intended to provide firm guidance but not absolute standards for transmission planning.

The design of BPA's transmission system is intended to meet the reliability performance requirements of all NERC, WECC and BPA planning standards and criteria.

8.3 Assumptions

The major assumptions that form the basis of the studies are load, generation, internal and external path flows, and transmission system topology. These assumptions are modeled in the WECC approved base cases which are used as the starting point for the assessment studies.

In addition, as part of base case development for the system assessment, base case assumptions for loads and resources are verified based on historical data and against the BPA White Book to ensure federal and regional load and resource obligations are captured. Each year, BPA Power Services publishes the *Pacific Northwest Loads and Resources Study* (White Book) which covers both federal and regional load and resource obligations. In addition, base case assumptions are coordinated with BPA Power Services to identify whether any other generation patterns need to be captured in the studies, and to capture any significant long-term resource outages from the Outage Resource Forecast.

To cover the planning horizon and the critical system conditions as required by the NERC Reliability Standards, BPA develops base cases for the Near-Term Planning Horizon which represents:

- Winter and summer peak load conditions for year one or two of the planning horizon
- Winter and summer peak load conditions for year five of the planning horizon, and
- Spring off-peak load conditions for one of the five years of the planning horizon

BPA also develops base cases for the long-term planning horizon which represents: winter and summer peak load conditions for year nine or ten of the planning horizon. For the 2017 and 2018 System Assessments, year nine was selected because it was the most current WECC approved base case representing the long-term planning horizon and therefore had the most updated loads, resource, and topology information with which to begin the assessment.

8.3.1 Base Cases

Base case assumptions for loads and resources are verified based on historical data and against the White Book to ensure federal and regional load and resource obligations are captured. Base case assumptions are also coordinated with BPA Power Services to identify whether any other generation patterns need to be captured in the studies, and to capture any significant long-term resource outages from the Outage Resource Forecast. For the 2018 System Assessment, BPA used the following WECC approved base cases as shown below. The 2019 System Assessment relied upon results from the 2017 and 2018 System Assessment to the extent possible. Therefore, the base cases used in the 2019 System Assessment are generally identical to what was used for the 2018 System Assessment.

2019 System Assessment Steady State Base Cases			
Year	Season	Load Level	Notes
2020	Summer	Off-Peak	Approximately 60% of summer peak loads
2020	Winter	Peak	Near term (2-year) expected winter peak
2020	Summer	Peak	Near term (2-year) expected summer peak
2023	Winter	Peak	Near term (5 year) expected winter peak
2023	Summer	Peak	Near term (5 year) expected summer peak
2028	Winter	Peak	Long-term (6-10 year) expected winter peak
2028	Summer	Peak	Long term (6-10 year) expected summer peak

Figure 6 Base Case Assumptions Table

8.3.2 Loads and Transfers

Transmission Planning coordinates with Power Services with regard to loads and transfers to ensure that what is modeled is adequate to meet Power Service's needs.

As required by the NERC Planning Standards, the transmission system is planned for expected load conditions over the range of forecast system demands. Normal summer and winter peak loads are based on a 50% probability of exceedance. Off-peak spring loads reflect a condition of approximately 65% of summer peak. Historical load levels for peak and off-peak load conditions are also examined to make sure the loads represented in the base cases are reasonable.

Also as required by the NERC Planning Standards, the transmission system is planned to meet projected firm transmission services over the range of forecast system demands. At a minimum, projected firm transmission obligations are modeled for the load area studies. In addition, the paths and interties are studied up to their transfer limits.

8.3.3 Resources

Transmission Planning coordinates with Power Services with regard to BPA's Federal Resources to ensure that what is modeled with respect to our generation patterns is adequate to meet Power Service's needs. At a minimum, the base cases model resources with assumed firm transmission service. Beyond that, other resources are modeled as needed to meet projected customer demands (load) and projected firm transmission service.

There is over 7000 MW of wind generation interconnected throughout the northwest. This is reflected in the WECC base case models. However, peak load reference cases used for the load area assessments typically assume minimal wind generation on-line. This assumption is made because of the intermittent nature of wind resources. This is consistent with historical data which shows that the output of wind generators has no definite correlation with load levels and is often quite low during peak load periods, which creates more limiting conditions for the load areas. For transmission paths which are affected by wind generation, wind sensitivity studies are conducted to assess the impact.

8.3.4 Topology and Future Projects

The transmission system topology is reviewed and updated with the latest information for the near term (one to five years out) and long term (six to ten years out) planning horizons. Since adding conceptual projects to the assessment could mask future system problems, most future proposed projects are not included in the near term base cases. The only future projects that are generally included in the near term cases are those where BPA or the sponsoring companies have made firm commitments to build the project within the next five years. These are typically projects that are currently under construction or, at a minimum, that have budget approval. In the longer term base cases, a limited number of future projects are modeled which may not have budget approval, but are considered likely to proceed. By including projects that utilities are actively pursuing, the next level of reinforcement needs can be identified and prioritized.

8.3.5 Remedial Action Schemes

At the transfer levels modeled in the base cases, remedial action schemes (RAS) may be used to ensure reliable operation of the transmission system. Some of these RAS will trip or ramp generation or load for specific contingencies. For the system assessment, RAS was modeled as appropriate based on the specific contingencies and system transfer levels that were modeled.

8.3.6 Transmission Facility Ratings

All BPA transmission facility ratings included in the system assessment are based on the latest information available in the Transmission System Electrical Data and Transformer Loading Guides. Ratings for non-BPA facilities are determined by the owner of the facility. The WECC System Criterion TPL-001-WECC-CRT-3 (which supplements the NERC Standards), requirement WR3 states: Each Transmission Planning and Planning Coordinator that uses a less stringent criterion than that stated in Requirement SR1 shall allow other Transmission Planners and Planner Coordinators to have the same impact on that part of the system for the same category of planning events (e.g., P1, P2). If another utility applies ratings other than equipment nameplate ratings for their facilities (such as emergency limits for a transformer); then BPA is permitted to apply the same limits as the other utility when meeting performance standards.

8.3.7 Reliability Standards and Criteria

The BPA transmission system is planned to meet applicable NERC Transmission System Planning Performance Requirements in Standard TPL-001-4. System tests and the required performance for those tests are established in the TPL-001-4 Standard. To meet the required performance for system normal and contingency events, BPA plans the transmission system consistent with the planning events and required performance established. These include the following planning events based on the TPL standards.

TPL-001-4 Category Events		
Normal System	P0	No Contingency
Single Contingency	P1	Single contingency of an element* or DC mono-pole
Single Contingency	P2	Bus section or internal breaker fault, or line section with no fault
Multiple Contingency	P3	Loss of generator plus an element*
Multiple Contingency	P4	Multiple elements* caused by stuck breaker
Multiple Contingency	P5	Multiple elements due to non-redundant relay failure
Multiple Contingency	P6	Loss of two single elements* with system adjustment in between
Multiple Contingency	P7	Loss of two circuits on common structure, or DC bi-pole

Note: Element refers to: a generator, transformer, transmission circuit, or shunt device

Figure 7 NERC TPL-001-4 Category Events List

8.3.8 WECC System Planning Performance Criterion

In addition to the NERC Planning Standards, BPA also applies the WECC Transmission System Planning Performance Criterion, TPL-001-WECC-CRT-3.1, where applicable.

8.4 Methodology

Once the transmission system is divided into load service areas and paths, each area is then studied under the limiting system conditions for that area. Each area is evaluated in order to identify any potential performance deficiencies and determine possible corrective action plans or confirm existing corrective action plans to meet applicable standards and criteria and ensure system reliability and cost-effectiveness. For each load area and path, studies are conducted to ensure that existing and forecast load and projected firm transmission service can be served throughout the planning horizon and that existing corrective action plans, such as system reinforcements, are adequate.

BPA also assesses the performance of 14 paths and 4 interties over the planning horizon. This includes an evaluation of the total transfer capability (TTC) of the path or intertie. This evaluation will confirm the TTC of the path or intertie. This evaluation will confirm that the TTC is sufficient over the planning horizon or identify potential corrective action plans needed to meet applicable standards and criteria to ensure system reliability.

The studies conducted for each load area and path includes steady state, voltage stability, and transient stability studies. And a short circuit analysis is conducted annually as part of BPA's Switchgear Replacement Program. Provided below is a general description of these items.

8.3.1 Steady State

The steady state timeframe is considered to be the period of time, generally greater than 30 minutes after a disturbance occurs, after all transients have settled out and automatic actions have occurred. For acceptable steady state system performance, equipment loadings must be within their ratings and voltages must be within applicable limits.

8.3.2 Voltage Stability

Voltage stability is assessed in the post-transient timeframe. This is the interval from one to several minutes following a disturbance after the transient response settles down. Voltage instability is a system state in which an increase in load, a disturbance, or a system change causes voltage to decay quickly or drift downward, and automatic and manual actions are unable to halt the decay. Voltage decay may take anywhere from a few seconds to tens of minutes. Unabated voltage decay can result in angular instability or voltage collapse depending on where it occurs. For voltage stability analysis, each bus on the transmission system is expected to maintain adequate reactive power margin in accordance with the WECC Transmission System Planning Performance Criterion. Voltage stability is required with the area modeled at a minimum of 105% of the reference load or transfer level for system normal conditions (P0) and for single contingencies (P1 & P2). For multiple contingencies (P3 - P7), voltage stability is required with the area modeled at a minimum of 102.5% of the reference load or transfer level.

8.3.3 Transient Stability

Transient stability is assessed for the timeframe from zero to tens of seconds. This timeframe assesses the dynamic performance of the transmission system during and immediately after an event occurs, usually initiated by a fault on the system. Transient stability is driven by large angle differences between coherent clusters of generation at the sending and receiving ends of a system. For transient stability analysis, the transmission system is expected to remain stable with damped oscillations, and voltage recovery and voltage dips are expected to remain within applicable limits in accordance with the WECC Transmission System Planning Performance Criterion.

8.3.4 Short-Circuit

A short circuit analysis is conducted annually by BPA's High Voltage Engineering group as part of BPA's Switchgear Replacement Program to determine whether circuit breakers have interrupting capability for faults they are expected to interrupt. The short circuit analysis is conducted for a five-year timeframe which covers the near-term planning horizon. In general, short circuit current is higher when more sources of current are modeled. Assumptions in the studies include modeling all grounding sources associated with busses serving load, and assuming all generation sources modeled on line. The worst case fault current through substation breakers is calculated looking at the case with all lines in service and by removing each line into the substation being studied.

8.5 System Assessment Summary Report

After the Area Planning technical studies are completed, Transmission Planning develops its annual System Assessment Summary report. The purpose of this report is to document BPA's system assessment to meet the NERC Reliability Planning (TPL) Standards. The System Assessment Summary Report provides an overall summary of the system assessment and how BPA meets compliance with the standards. It is also provides compliance evidence and supporting documentation for the annual self-certification and WECC audits. The information in the report is considered critical energy infrastructure information and distribution is controlled.

9. Non-Wires Assessment

9.1 Purpose of Non-Wires Alternatives

Transmission Planning along with the BPA Cross-Agency Non-Wires team explores possible non-wires solutions that include a broad array of alternatives such as demand response, distributed generation, and energy-efficiency measures that can individually or in combination delay or eliminate a need for reinforcements to the transmission system.

9.2 New Non-Wires Assessment Information

New this year is a brief summary of the non-wires assessment for each of the 24 load areas. This new information is provided for each load area in the Transmission Needs section of this plan. Rather than provide a stand-alone non-wires document in the Appendix of this plan, the non-wires summary information is provided in context with the load area information. The non-wires summary is provided in each of the area sections along with other details such as an area description, local generation and load data, historical and forecasted peak load values, and a brief description of remedial action schemes. Following the non-wires information, the proposed, deferred, and completed transmission plans of service are listed. This collection of information gives a more robust picture of the transmission plan for each of the 24 load areas.

9.3 Area Planning Non-Wires Assessment

Each year a qualitative analysis of potential non-wires alternatives is included in each area technical report during the annual area planning process. For areas that have performance deficiencies and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct the deficiency or defer the date when a project is required to comply with the NERC Standards is described. Alternatively, for those areas with no recommended projects, the potential for non-wires measures to slow or flatten the load growth in the area is considered, which may defer the need for reinforcements identified in the future.

9.4 Non-Wires Summary and Prioritization Reports

Transmission Planning produces an internal Non-Wires Summary Report that provides information about non-wires potential in each of the 24 load areas. This internal report is used to help identify those areas which appear to have the greatest potential for non-wires measures. Typically the top three to five candidate areas are selected as the highest priority for further non-wires evaluation. These top candidate areas, together with the factors contributing to the ranking, are summarized in the annual Non-Wires Prioritization Report. This prioritization report is produced by Planning in collaboration with the cross-agency Non-Wires team. Following the prioritization process, one or more of the candidate areas are selected for more detailed non-wires analysis and possible implementation measures.

9.5 Non-Wires Planning Process Diagram

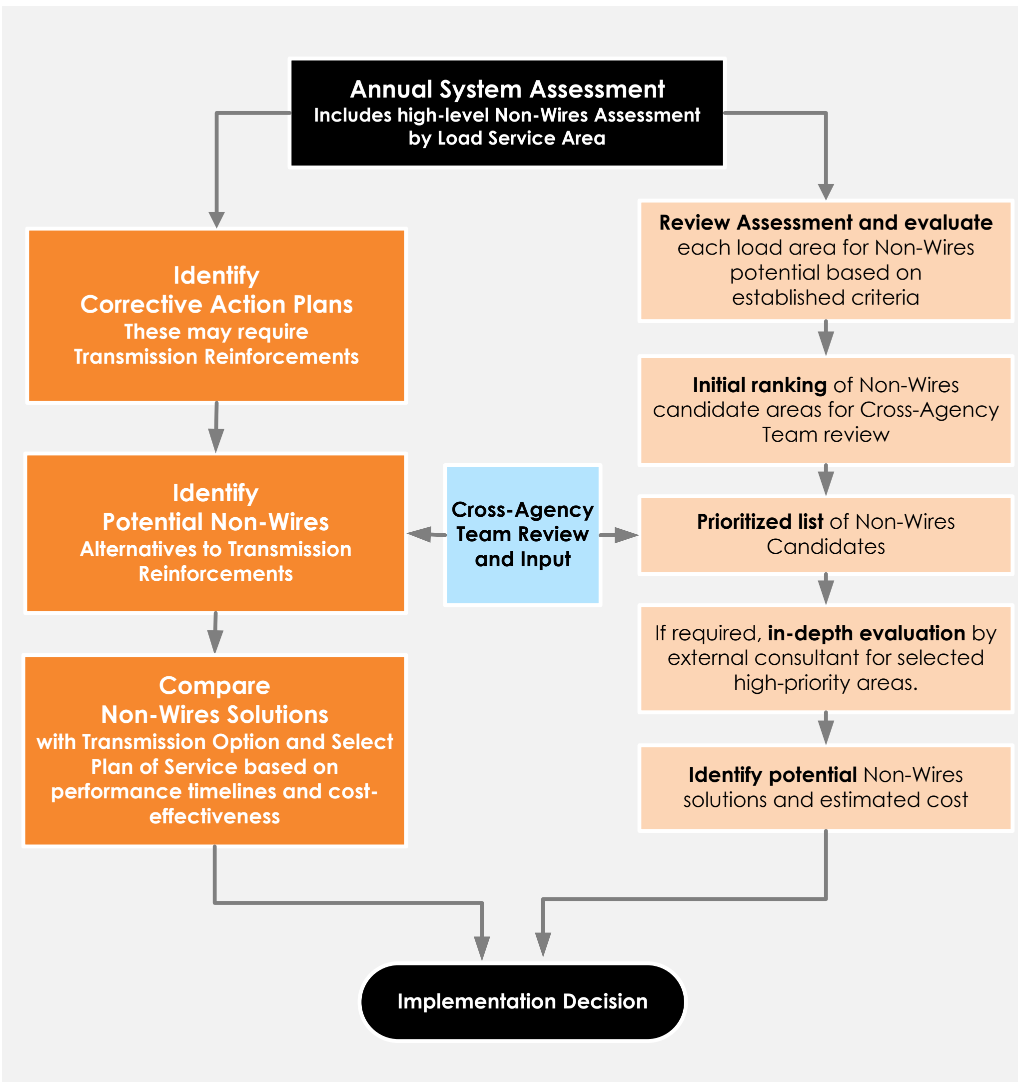


Figure 8 Non-Wires Planning Process Diagram

10. Transmission Service Requests

The Transmission Service Requests Study and Expansion Process (TSEP) is BPA's process to manage and respond to Long-Term Firm Transmission Service Requests (TSR) on the BPA network. The TSEP is a process to plan for, and grant transmission service to, Network (NT) customers consistent with BPA's statutory authorities and BPA's tariff obligations, while granting timely service to those customers seeking Point-to-Point (PTP) service. It is intended to be a repetitive and effective process that provides a balance in serving different customer classes (PTP and NT) on a non-discriminatory basis.

BPA provides wholesale transmission service in accordance with its Open Access Transmission Tariff (OATT) and supporting business practices. BPA's process for evaluating and responding to transmission service requests largely mirrors the method defined by the Federal Regulatory Commission's pro forma tariff. BPA has a 30-day response requirement to notify the requesting customer whether BPA can provide the requested service without requiring a study. If the existing system cannot enable the request, BPA is obligated to offer to study and identify plans of service to update the transmission system.

Bonneville Power Administration Transmission (BPAT) services provides notice that it will conduct a Cluster Study of transmission service requests and forecasted network resources for service over the network portion of the Federal Columbia River Transmission Service. The Cluster Study is conducted pursuant to sections 19.10 and 32.6 of BPAT's OATT. BPAT requires participants to execute a Cluster Study Agreement and to provide advance payment of their pro-rata share of the estimated study costs. A cluster study is essentially a group of customer requests for service combined into one large system impact and facility study. This method ensures a holistic examination of total system impacts. Customers have the option to request to be studied on an individual basis, at the conclusion of the Cluster Study. The purpose of the Cluster Study is to determine how much available transfer capability can be offered and which new facilities, if any, will be required to accommodate customer requests for transmission service.

BPA posts a notice on its OASIS and emails all stakeholders of its intent to conduct a Cluster Study. Notice is generally posted 45-60 days in advance of the deadline for customers to submit requests. This notice includes the rationale, eligibility requirements and the deadline for customers to submit requests. BPA strives to complete the Cluster Study within a 120-day period. Study results include: costs of any directly assignable facilities that will be charged to the customer; a customer's estimated pro-rata share of network upgrade costs; and an estimated time to complete the network upgrades.

Transmission Planning conducts the Cluster Study analysis as part of the process to manage and respond to requests for TSR on the BPA network. BPA contractually and financially secures a long-term firm commitment from customers with eligible TSRs to purchase long-term firm transmission service. To initiate the process BPA offers an agreement to all customers with a network TSR in the OASIS queue.

Below are the TSEP and Cluster Study General Timelines.

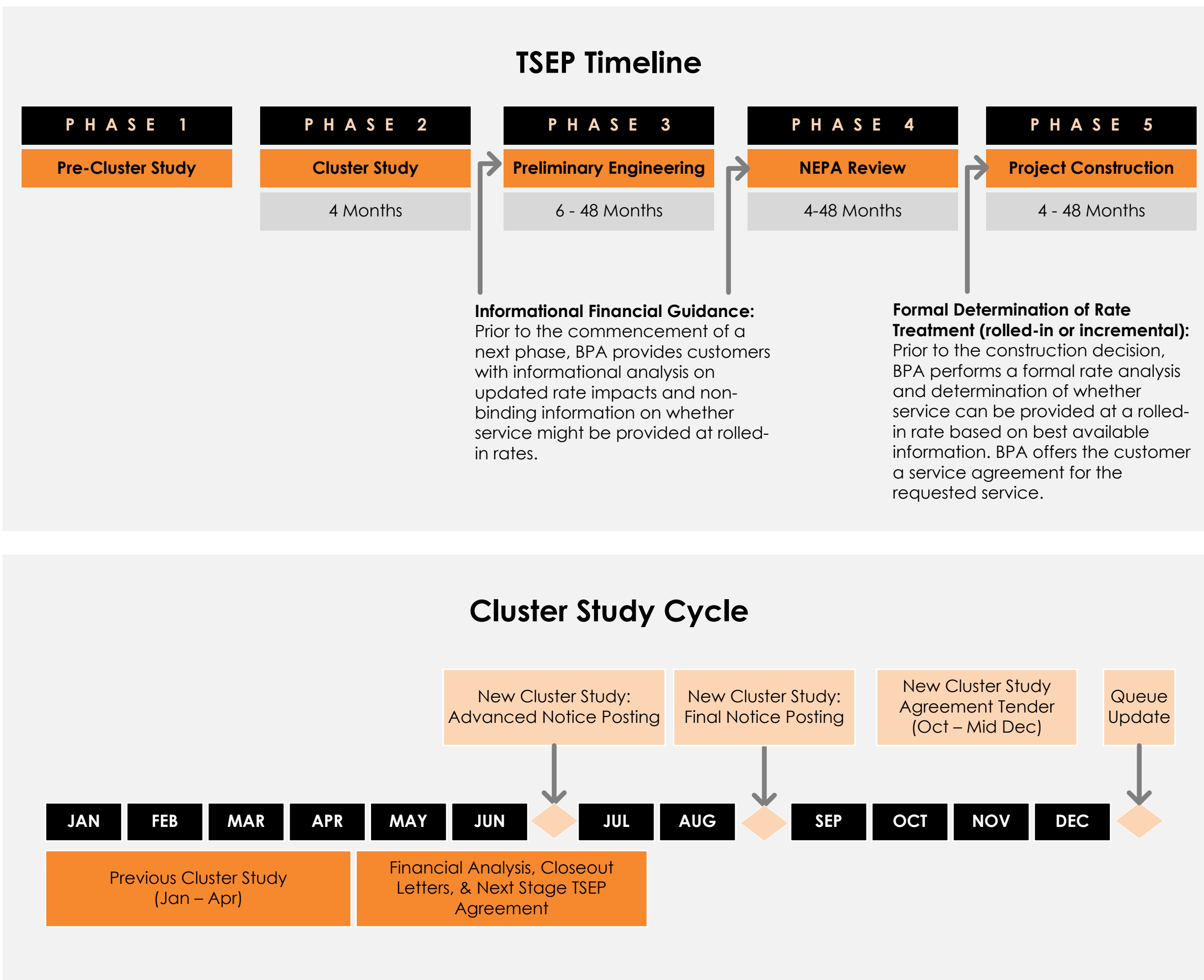


Figure 9 Cluster Study General Timeline Diagram

10.1 Elements of TSEP

Phase 1: Pre-Study

- Customer TSR submittal and available transfer capability assessment
- Period between close of last TSR deadline and next TSR deadline for cluster study participation
- TSR deposit and processing fee
- Data Exhibit submittal and validation

Phase 2: Cluster Study

- BPA tenders study agreements following TSR deadline
- Customer submits study deposit
- BPA commences and completes and study (120-day period)
- Results: preliminary plan of service scope, cost and schedule
- Customer's pro-rata share of costs by MW

Phase 2.b: Non-Cluster Study TSRs (Opt-out for study on an individual basis)

- If there are any opt-outs for individual study, determine the BPA point of contact (TPP, TSE, or TPC) in line with the GI & LLI processes
- The point of contact must inform customer directly (via email) of any delays (and new estimated completion date) or other necessary communication, including the delay due to the cluster study
- BPA study and reporting as per TSR process

Phase 3: Preliminary Engineering

- Refinement of cost and scope of cluster study results
- Estimate of environmental review scope and costs
- Customer's pro-rata share of costs by MW

Phase 4: Environmental Review

- Required NEPA review of environmental impacts based on identified plan of service
- Includes record of decision on preferred rout and whether to build the project
- Customer's pro-rate share of costs by MW

Phase 5: Project Construction

- Construction and energization of identified transmission project
- Customer secures its pro-rate MW share of construction costs (letter of credit, etc.)

Figure 10 Transmission Service Request Study and Expansion Process List

10.2 TSEP Cluster Study Purpose

Transmission Planning conducts the Cluster Study analysis of Transmission Service Requests (TSR) and determines the transmission reinforcement requirements to accommodate the transmission service. The purpose of the Cluster Study is to determine how much available transfer capability can be offered and which new facilities, if any, will be required to accommodate customer requests for transmission service. A Cluster Study simultaneously evaluates, by aggregating multiple TSRs into a cluster, all customer requests for long-term firm transmission service and evaluates total demand across its network paths.

10.3 2019 Cluster Study Overview

The 2019 Cluster Study was completed mid-2019. There were 17 customers, 105 transmission service requests with a total megawatt of 3,993. Of the 105 requests, 104 were point-to-point. Five customers accounted for 82 percent of all the requests. The total megawatts are comprised of three customer classes: developer (93%), investor-owned utility (6%), and marketer (2%). See the Appendix for summary information on plans of service and estimated costs. Also, visit the BPA web site for more details about the 2019 Cluster Study and the upcoming 2020 Cluster Study.

10.4 TSEP Cluster Study Steps

- BPA would validate all PTP/NT Data Exhibit submittals that identify the location of the resource supplying the energy and capacity and the ultimate load that receives the transmitted energy and capacity.

- BPA would then offer Cluster Study Agreements (CSA) for all eligible TSRs. The CSA obligates the customer to pay for its pro-rata share of the Cluster Study.

- BPA next "re-stacks" the transmission queue by removing TSRs for which customers failed to return executed CSAs. BPA-TS would then determine if it is able to make offers of service based on existing ATC to any of the TSRs that remain in the queue.

- BPA would then perform a CS to determine transmission expansion, if any, required to accommodate service to TSRs for which there is insufficient ATC. BPA-TS would then prepare a Cluster Study Report that describes the results of the CS.

- For new transmission reinforcements identified in the CS, BPA-TS next conducts a preliminary financial analysis based on the TSRs plus the costs of the transmission reinforcements.

10.5 Cluster Study Report

The Cluster Study report summarizes the findings of the analysis and power flow modeling that is conducted and includes a list of projects. It also provides information about the methodology employed for the current Cluster Study, including study areas, generation scenarios, and generation sensitivities. It may also provide background on projects completed outside TSEP and projects from the previous Network Open Season, and other reliability or load service projects.

10.6 Cluster Study Process

The diagram below depicts the current Cluster Study process from Transmission Planning's perspective. It is provided for informational purposes only. BPA customers who request transmission service may do so during a limited-time submission window (a.k.a. open season). After the request for transmission service window closes, agreements are offered to all eligible customers who made a TSR. This agreement obligates the customer to pay for its pro-rata share of the Cluster Study costs.

The transmission queue is first restacked by removing TSRs for which customers failed to return an executed agreement including sufficient data exhibits. The remaining TSRs are evaluated to see if existing LT ATC (as informed by the LT ATC Update) can accommodate any potential offers of service. TSRs with cumulative material impacts that exceed the LT ATC for any impacted flow gate are included in the Cluster Study. BPA then determines if it is able to make offers of service based on existing LT ATC to any of the TSRs that remain in the queue.

Transmission Planning performs a Cluster Study to determine additional facilities, if any, required to accommodate service to TSRs for which there is insufficient LT ATC. Transmission Planning proceeds with detailed technical studies and flow-based studies. Based on the study's results, potential projects are identified.

Transmission Planning
Cluster Study Process

Figure 11 Cluster Study Process Diagram

10.7 Cluster Study Methodology

10.7.1 Introduction

The Cluster Study includes four fundamental elements:

1. Determine which requests could be accommodated by the existing system.
2. Determine which requests require system reinforcement.
3. Develop plans of service for requests that require system reinforcement.
4. Demonstrate that the interconnected transmission system, together with the identified reinforcements, is able to accommodate the requested service.

10.7.2 ATC and Sub-Grid Assessment

BPA performs an Available Transfer Capability (ATC) assessment for each TSR – paired with a sub-grid check – to determine which TSRs can be served by the existing system or which TSRs would need reinforcements to provide the requested service.

The assessment considers BPA's pending queue for long-term firm transmission service after all TSRs are removed for customers that elected not to sign a Customer Service Agreement. Remaining TSRs are evaluated to see if any potential offers of service based on the impacts from requested Points of Receipt (POR) and Points of Delivery (POD) on BPA's Network can be made.

Following the assessment of ATC, BPA performs a sub-grid check on each TSR to consider impacts on other facilities that are not part of the monitored flow gates. The sub-grid checks rely, to the maximum extent possible, on operational experience and previous studies (such as Generation Interconnection studies) to identify where reliability concerns exist.

If the combined ATC assessment and the sub-grid check confirm that the existing system can accommodate the requested service, the TSR is considered for possible authorization. If a TSR has non-*de minimis* impacts that exceed the ATC for any flowrate or has an adverse sub-grid impact, the CS further evaluates the TSR in order to identify the transmission expansion necessary to provide the requested service.

10.7.3 Determination of Cluster Study Areas

For all TSRs that require further evaluation to determine transmission reinforcements to accommodate the requested service, BPA-TS combines TSRs with similar PORs (i.e., those PORs that are close enough to cause similar impacts on the transmission system). These combinations result in forming Cluster Study areas that are studied together in more detail to identify plans of service that can accommodate the requested service.

Detailed technical studies are performed on each of the study areas to define the actual reinforcements needed. These studies consider a combination of firm and non-firm uses of the system including load growth, interconnection projects, and projects on adjacent systems that are included in traditional planning methods. The result is a more robust transmission expansion plan to meet the expected, as well as requested, obligations of the system.

10.7.4 Generation Scenarios

Included below is a description of how hydro, thermal, wind, and solar generation may be modeled. The generation scenarios are developed from Western Electricity Coordinating Council (WECC) approved heavy summer and heavy winter base cases. BPA-TS developed generation scenarios to help inform the requirements for providing firm transmission. Three zonal hydro generation scenarios are analyzed – Upper Columbia, Lower Columbia, and a Lower Snake stress – with a combination of binary scenarios for the Canadian Entitlement Return and Wind generation (on and off). Balancing of the resources to meet the loads and losses in each case is implemented on a pro rata basis for all generation online.

10.7.5 Hydro Generation

The Federal Columbia River Power System (FCRPS) generation may be dispatched to create three separate zonal stresses. These patterns are intended to reflect how FCRPS operation meets non-power constraints and obligations. Each zonal stress pattern provides for the nameplate less expected generation outages for all of the FCRPS projects in a zone for the appropriate season. The zones include the Upper Columbia, Lower Columbia and Lower Snake.

10.7.6 Thermal Generation

The thermal generation may be dispatched at the lower of historical peak or 100% of requested amount. Thermal generation may not be tested as a binary scenario.

10.7.7 Wind Generation

The wind generation scenarios reflect true operating conditions with high correlation. The peak wind generation may be modeled at the lower of historical peak or 100% of requested amount. Wind generation may be tested at the zero output level. The No Wind scenario yielded information about how the system might be expected to perform during extended periods of no wind conditions. The High Wind Scenario yielded information about how the system might be expected to perform during extended periods of high wind conditions that could lead to reduction in dispatch of non-wind resources that supply load within the region.

10.7.8 Solar Generation

Solar generation may be dispatched at 100% of the requested amount. Solar generation may not be tested as a binary scenario.

11. Interconnection Service Requests

BPA Transmission Services provides services for interconnection to the Federal Columbia River Transmission System. BPA receives Generator Interconnection (GI) requests according to Attachment L Large Generator Interconnection Process (LGIP) and Attachment N Small Generator Interconnection Process (SGIP) of the BPA Open Access Transmission Tariff. The GI projects listed in this T-Plan include large (greater than 20 megawatts) generator interconnection projects.

Customers may also request new points of interconnection on BPA's transmission system. These Line and Load Interconnections (LLI) are typically for new load addition or to allow the customer to shift the point of delivery to different points on BPA' system. The interconnection of lines and loads is also governed by BPA's OATT. Similar to the generator interconnection projects, only projects which have an executed interconnection or construction agreement are included in this T-Plan.

11.1 Generation Interconnection Process

When a customer makes a request for a generator interconnection, Transmission Planning conducts and supports three studies:

- Interconnection Feasibility Study [FES]
- Interconnection System Impact Study [ISIS]
- Interconnection Facilities Study [FAS]

11.1.1 Feasibility Study and Report

Transmission Planning conducts a feasibility study when a project warrants a need; however, there are work interdepencies among Transmission Planning and Customer Service. Execution of the FES Agreement is optional if BPA and the customer agree. If a FES is needed, Transmission Planning performs power flow steady state analysis, produces a sketch of the project, and determines typical costs and schedule. A feasiblity study report provides preliminary identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection; of any thermal overload or voltage limit violations resulting from the interconnection; and a non-binding estimated cost of facilities required to interconnect the large generating facility to the transmission system and to address the identified short circuit and power flow issues. The customer pays a study deposit for the FES. The LGIP specifies 45 days for BPA Transmission Services to provide the FES report. The FES is followed up with a FES results meeting conducted by BPA Customer Service.

11.1.2 System Impact Study and Report

Transmission Planning performs voltage stability and transient stability analysis, reviews fault duty studies, and produces the ISIS report. A project requirements diagram is developed and a typical cost and schedule are determined. The ISIS is based upon the results of the FES and the technical information provided by the interconnection customer in the interconnection request. The customer pays the study deposit for the ISIS. The ISIS report provides the identification of any circuit breaker short circuit capability limits exceeded as result of the interconnection; identification of any thermal overload or voltage limit violations resulting from the interconnection; identification of any instability or inadequately damped response to system disturbances resulting from the interconnection; and a description and non-binding, good-faith estimated cost of facilities required to interconnect the generating facility to the transmission system and to address the identified short circuit, instability, and power flow issues. The LGIP specifies 90 days for BPA Transmission Services to provide the SIS report. The ISIS is followed up by a results meeting with the customer.

11.1.3 Facilities Study and Report

Transmission Planning provides a cost estimate to implement the conclusion of the Interconnection System Impact study including costs of equipment, engineering, procurement, and construction. The Facilities study also identifies the electrical switching configuration of the connection equipment, including transformers, switchgear, meters and other station equipment. This information is relayed in the form of a Project Requirements Diagram. The FAS report provides a description, estimated cost, and schedule for required facilities to interconnect the generating facility to the transmission system, and addresses the short circuit, instability, and power flow issues identified in the ISIS. The LGIP specifies 90 days for BPA Transmission Services to provide the FAS report with a +/- 20% cost estimate, or 180 days to provide a FAS report with a +/- 10% cost estimate. The BPA scoping process is now conducted during the facility study phase and may extended the time to complete the study. The FAS report is followed up with a FAS results meeting with the customer.

11.2 Line and Load Interconnection Process

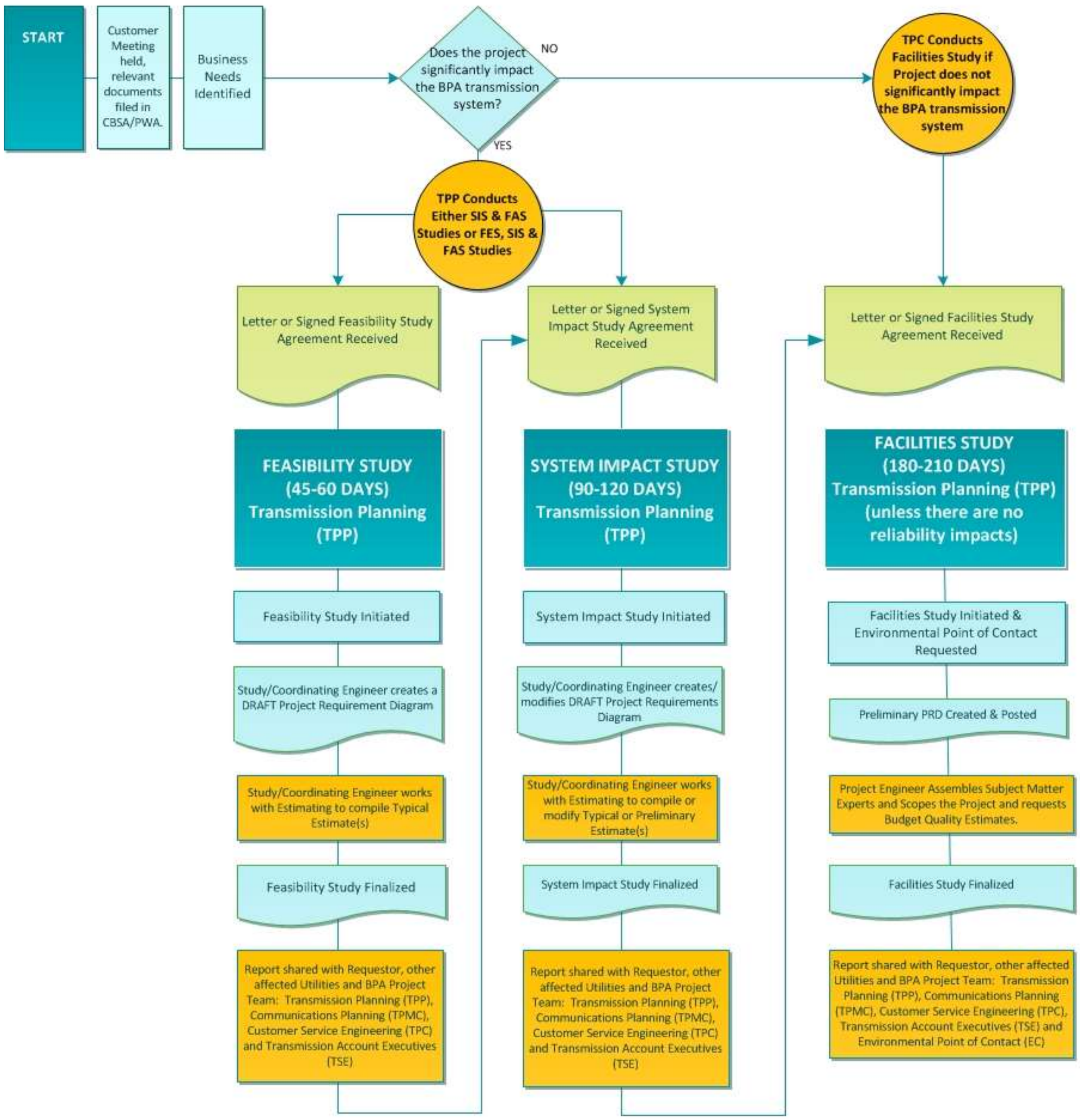
When a customer makes a request for a new line or load addition, Transmission Planning conducts and supports development of up to three studies:

- Interconnection Feasibility Study [LLFES]
- Interconnection System Impact Study [LLISIS]
- Interconnection Facilities Study [LLIFAS]

Click here for additional Information about interconnections.

On the next page is a study process diagram for transmission interconnection service requests.

Tranmission Planning
Generation and Line-Load Interconnection Study Process



Coordination and cooperation is completed through normal and informal day to day communication and interactions between TPP, TPMC and TPC. No formal procedure is established for this work.

Figure 12 Interconnection Study Process Diagram

TRANSMISSION PLANNING

12. Bonneville Maps

12.1 Service Territory, Transmission Lines, Service Areas and Federal Dams

The Bonneville Power Administration is a nonprofit federal power marketing administration based in the Pacific Northwest. Although BPA is part of the U.S. Department of Energy, it is self-funding and covers its costs by selling its products and services. BPA markets wholesale electrical power from 31 federal hydroelectric projects in the Northwest, one nonfederal nuclear plant and several small nonfederal power plants. The dams are operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation. The nonfederal nuclear plant, Columbia Generating Station, is owned and operated by Energy Northwest, a joint operating agency of the state of Washington. BPA provides about 28 percent of the electric power used in the Northwest and its resources — primarily hydroelectric — make BPA power nearly carbon free.

BPA also operates and maintains about three-fourths of the high-voltage transmission in its service territory. BPA's territory includes Idaho, Oregon, Washington, western Montana and small parts of eastern Montana, California, Nevada, Utah and Wyoming.

The BPA transmission system is characterized primarily by hydro generation on the main stem Columbia and lower Snake River that are remote from load centers. Most of the generation is run-of-the-river hydro. In addition, there are several thermal generators located along the I-5 corridor from Seattle to Portland.

Below are maps of the Bonneville service territory, transmission lines, customer services area, load service areas, paths and interties.

Figure 13 BPA Service Territory Map

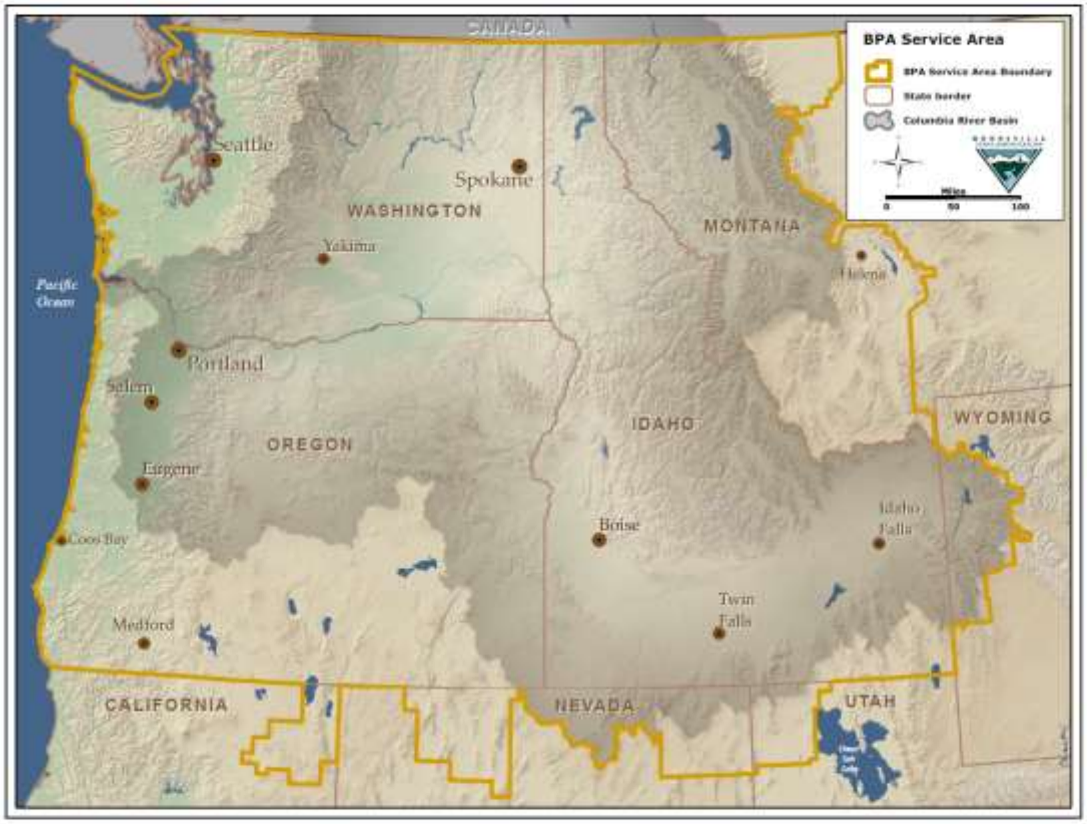


Figure 14 BPA Transmission Lines

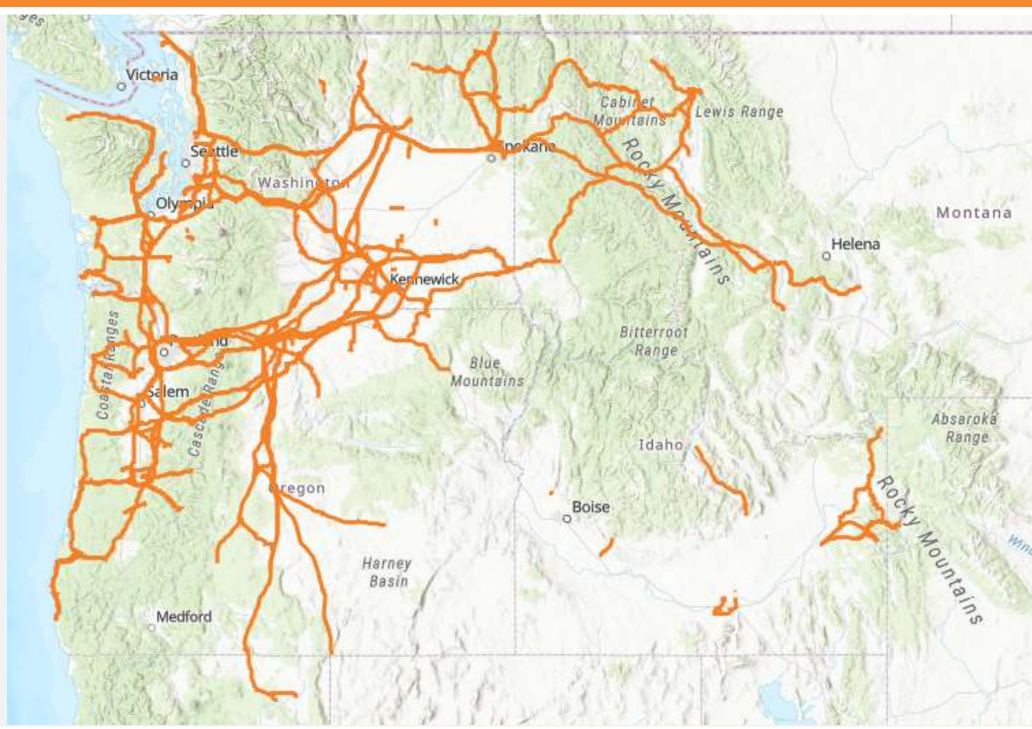


Figure 15 BPA Public, Tribal and Investor Owned Utility Service Areas

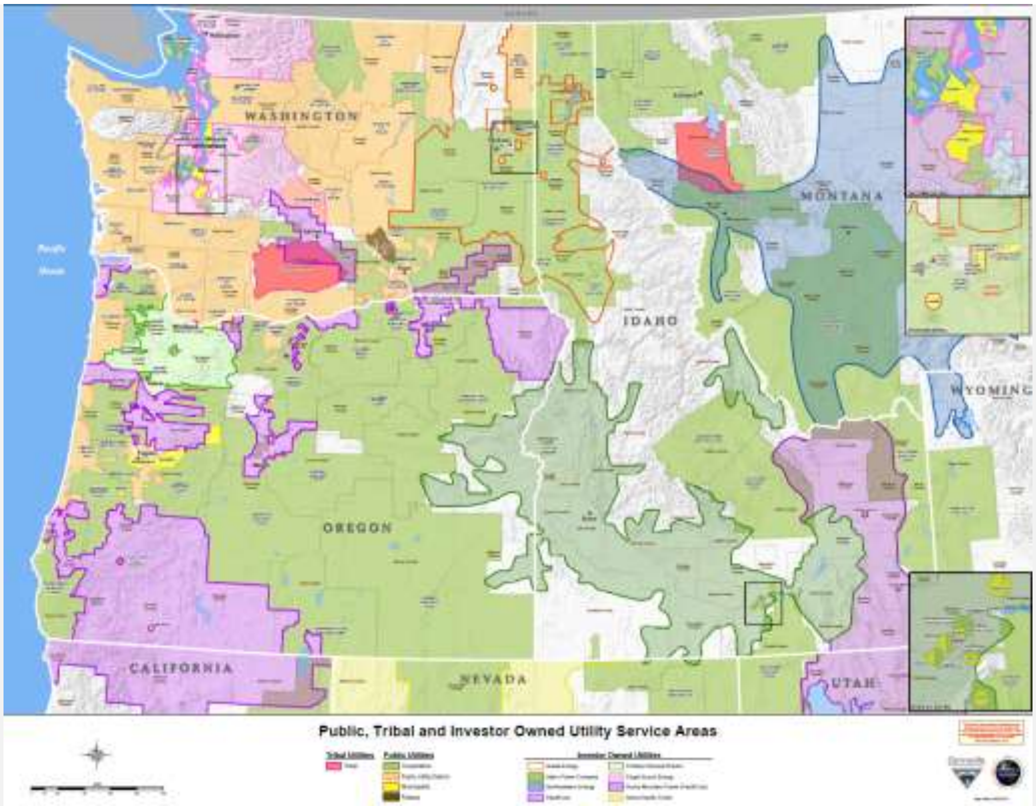
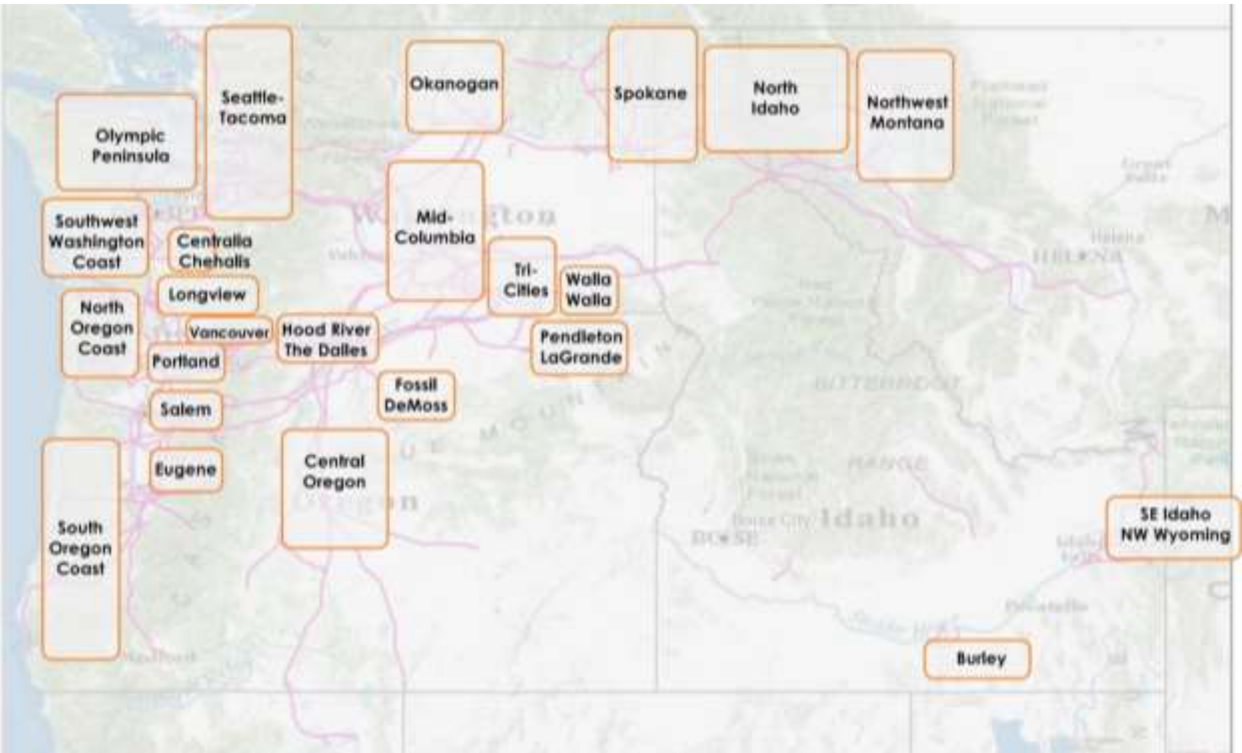


Figure 16 Main Stem of Columbia and Lower Snake Rivers Map – 31 Federal Dams

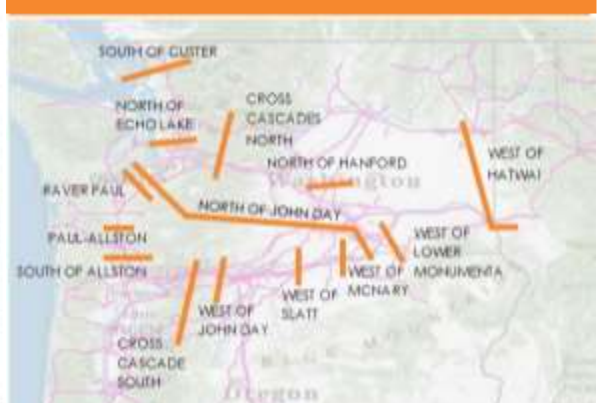
12.2 Transmission Planning Load Service Areas

Figure 17 Load Service Areas, Interties and Paths



INTERTIES

PATHS



List of Area, Paths and Interties

Load Service Areas

1	Seattle, Tacoma, and Olympia	13	Centralia, Chehalis
2	Portland	14	Northwest Montana
3	Vancouver	15	Southeast Idaho and Northwest Wyoming
4	Salem, Albany	16	North Idaho
5	Eugene	17	North Oregon Coast
6	Olympic Peninsula	18	South Oregon Coast
7	Tri-Cities (includes Boardman)	19	De Moss, Fossil
8	Longview	20	Okanogan
9	Mid-Columbia	21	Hood River, The Dalles
10	Central Oregon (includes Alturas)	22	Pendleton, LaGrande
11	Southwest Washington Coast	23	Walla Walla
12	Spokane, Colville, Boundary	24	Burley (Southern Idaho)

Paths		Interties	
1	North-of-John Day	1	California Oregon Intertie
2	North-of-Hanford	2	Pacific DC Intertie
3	West-of-McNary	3	Northwest-Canada
4	West-of-Slatt	4	Montana to Northwest
5	West-of-John Day		
6	Raver-Paul		
7	Paul-Allston		
8	South-of-Allston		
9	West-of-Cascades South		
10	North-of-Echo Lake		
11	South-of-Custer		
12	West-of-Cascades North		
13	West-of-Hatwai		
14	West-of-Lower Monumental		

This page is intentionally left blank.

13. Transmission Needs

On an annual basis, Transmission Planning provides a ten-year plan for reinforcements to BPA's transmission system and is provided in accordance with Attachment K of the BPA Open Access Transmission Tariff. This section provides a narrative description of the transmission needs identified through the transmission planning process, the preferred alternative, an estimated cost, and estimated schedule for completion of the preferred alternative. It also reflects any plans for facilities needed to provide requested interconnection or long-term firm transmission service on BPA's system. The objective of this section is to identify and describe reinforcement projects for the transmission system. It contains proposed projects identified to meet the forecast requirements of BPA and other customers over the 10-year planning horizon. This section provides the proposed new facilities organized by type of project. The types of projects include the following.

- Projects required to provide load service and meet Planning Reliability Standards,
- Project to improve operational or maintenance flexibility,
- Projects required to meet requests for transmission service,
- Projects required to meet requests for Generator Interconnection service, and
- Projects required to meet requests for Line and Load Interconnection service.

Some projects may satisfy multiple criteria; however they will only be described once. In addition to proposed projects, this section includes a listing of Recently Completed Projects for each load area or path. This category includes projects which have been completed since the previous update to the BPA Plan and includes assessment findings. Where applicable, there is also a category called Deferred Plans of Service. This consists of plans of service which have been mentioned in previous BPA Plans; however the present year's system assessment shows the need date has moved beyond the planning horizon. This is typically a result of reduced load growth resulting in changes to the load forecast for the particular area.

NOTES: Estimated Project Costs are direct costs (overheads are not included). Where official cost estimates have not been developed, the indicated project cost reflects the best information available, based on typical costs of similar projects.

13.1 Transmission Needs by Load Service Area

13.1.1 Seattle/Tacoma/Olympia Area

The Seattle/Tacoma Load Area has a large footprint, spanning from Bellingham and the Canadian border, all the way south to the Tacoma/Olympia metro area; and spans east from the Puget Sound to the foothills of the Cascade Mountains. The Seattle/Tacoma load area can be divided into 2 sub-areas: Seattle/Bellingham/Everett and Tacoma/Olympia. It is the largest load area in the entire Pacific Northwest and one of the largest load areas in the entire WECC Interconnected System. It includes major metropolitan areas surrounding North Tacoma, Greater Seattle Metro Area, Everett, and Bellingham. The area includes Pierce, Thurston, North Lewis and South King counties. It is bordered on the north by Canada and on the south by Olympia. It is bordered on the east by the Cascade Mountains and on the west by the Puget Sound. To the north, the Seattle metropolitan area includes Blaine, Bellingham, Sedro Woolley and Mount Vernon and to the south the Seattle metropolitan area includes Puyallup and Olympia.

The customers in this area include:

- Whatcom County Public Utility District (WPUD)
- Puget Sound Energy (PSE)
- Seattle City Light (SCL)
- Snohomish County Public Utility District (SPUD)
- Tacoma Power Utilities (TPU)
- Alder Mutual Light Co. (Alder)
- City of Eatonville (COE)
- City of Milton (Milton)
- City of Steilacoom (COS)
- Elmhurst Light and Power (EL&P)
- Lakeview Light and Power (LL&P)
- Ohop Mutual Light (OML)
- Parkland Light and Power (PL&P)
- Peninsula Light (PI)

Seattle/Tacoma/Olympia Area

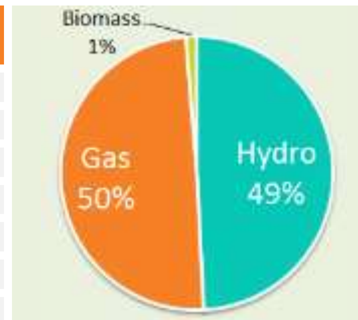
The load area is served by the following major transmission paths or lines:

- From the north by the Northwest-British Columbia path (or Northern Intertie)
- From the east by the West of Cascades North path
- From the south by the Raver-Paul path
- From the west by the Satsop-Olympia 230 kV and Satsop-Paul 500 kV lines

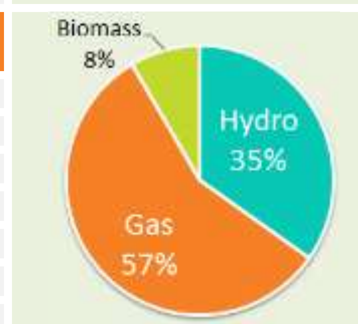
Local Generation and Load

The Seattle/Bellingham area has over 2500 MW of local generation which consists primarily of hydro and thermal (coal and gas-fired) generators. The Tacoma/Olympia are has approximately 750 MW of local generation.

Seattle/Bellingham Sub-Area	Fuel	Max. MW	Owner
PSA Generators			
Enserch	Gas	185	PSE
Fredonia	Gas	320	PSE
Sawmill (Fredonia)	Biomass	33	PSE
Komo (Shannon/Baker)	Hydro	13	PSE
Lower Baker	Hydro	85	PSE
Upper Baker	Hydro	105	PSE
March Point (Texaco)	Gas	150	PSE
Ferndale	Gas	280	PSE
Sumas	Gas	140	PSE
Whitehorn	Gas	180	PSE
Diablo	Hydro	170	SCL
Gorge	Hydro	180	SCL
Ross	Hydro	450	SCL
Jackson	Hydro	120	SNPD
Other Generators			
Cedar Falls	Hydro	30	SCL
Tolt River	Hydro	17	PSE
Twin Falls	Hydro	25	PSE
Snoqualmie Falls	Hydro	54	PSE
TOTAL		**2,537**	



Tacoma/Olympia Sub-Area	Fuel	Max. MW	Owner
Alder	Hydro	50	TPU
Frederickson, LLP (230)	Gas	270	BPA/PSE
Frederickson, PSE (115)	Gas	160	PSE
Cushman	Hydro	145	TPU
LaGrande	Hydro	69	TPU
Simpson	Biomass	64	TPU
TOTAL		**758**	



Seattle/Tacoma/Olympia Area

A historic winter peak was reached for Seattle in December 2008 during a cold event of 6,874 MW. A historic winter peak was reached for Tacoma in January 2008 during a cold event) of 3,047 MW. A peak Seattle summer load of 5,120 MW occurred in 2009 and a peak Tacoma summer load of 1,990 MW occurred in 2009.

Seattle/Tacoma/Olympia Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
6644	9123	6699	9438	6792	9565	0.3	0.3

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

The load reduction required to keep the winter peak load flat is 9.5 MW per year and 16.5 MW per year in Seattle and Tacoma. The load reduction required to keep the summer peak load flat is 70 MW per year and 11 MW per year in Seattle and Tacoma.

Re-dispatch of generation in the Puget Sound Area (PSA) is the single most effective non-wires solution to congestion in the Seattle/Tacoma load area. Redispatch is a request issued by the transmission system operator to power plants to adjust the real power they input in order to avoid or eliminate congestion. Several attempts in the past to implement re-dispatch amongst the Puget Sound Area utilities and BPA have been met with extraordinary commercial, contractual and legal challenges. In addition, most of the utilities in the PSA have historically expressed a preference to build transmission to resolve congestion and maximize generation flexibility rather than relying on re-dispatch solutions.

As future regulatory implications for PSA utility generating plants become more stringent, it is increasingly less feasible to rely on generation re-dispatch mechanisms as most of the PSA generation facilities are single or combine cycle natural gas plants. As transmission becomes more expensive to build and physically harder to site, generation re-dispatch remains a viable non-wires alternative and can be pursued as a method for mitigating peak load forecasts.

Seattle/Tacoma/Olympia Area

Proposed Plans of Service

Raver 500/230 kV Transformer (PSANI)

- Description: This project adds a 1300 MVA, 500/230 kV transformer at Raver Substation. This project is part of the overall Puget Sound Area/Northern Intertie (PSANI) Regional Reinforcement Plan. This is a joint project between participating utilities in the Puget Sound area.
- Purpose: This project is required to support load growth in the Puget Sound area.
- Estimated Cost: $72,000,000
- Expected Energization: 2020

Monroe-Novelty 230 kV Line Upgrade

- Description: This project upgrades the Monroe-Novelty 230 kV line from 60 to at least 80 degree C.
- Purpose: This project improves reliability for the Puget Sound load area.
- Estimated Cost: $1,000,000
- Expected Energization: 2021

Tacoma 230 kV Series Bus Sectionalizing Breaker
(This project is combined with Tacoma 230 kV Bus tie Breaker project below.)

- Description: This project adds a 230 kV series bus sectionalizing breaker at Tacoma Substation.
- Purpose: This project mitigates issues caused by a 230 kV bus sectionalizing breaker failure at Tacoma Substation.
- Estimated Cost: $2,300,000
- Expected Energization: 2021

Tacoma 230 kV Bus Tie Breaker
(This project is combined with the Tacoma 230 kV Series Bus Sectionalizing Breaker project above.)

- Description: This project adds a 230 kV bus tie breaker, and a 230 kV auxiliary bus sectionalizing disconnect switch at Tacoma Substation.
- Purpose: This project improves the operations and maintenance flexibility at Tacoma Substation.
- Estimated Cost: See above.
- Expected Energization: See above.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.2 Portland Area

The Portland load service area includes the greater Portland metropolitan area in Oregon and the surrounding communities of Troutdale, Gresham, Sandy, Beaverton, Hillsboro, Tigard, Tualatin and Wilsonville, Oregon. This area includes Multnomah, Washington, northeast Clackamas, and south Columbia counties. The Portland area extends north to the Columbia River and south to the Salem area. It extends west to Tigard, Oregon and east to the Cascade Mountain range.

The customers in this area include:

- Portland General Electric (PGE)
- PacifiCorp (PAC)
- City of Forest Grove
- Western Oregon Electric Coop.
- Columbia River Public Utility District
- McMinnville Water and Light

The load area is served by the following major transmission paths or lines:

- From the north by the Paul-Allston path
- From the south by the Pearl-Ostrander and Pearl-Marion 500 kV lines
- From the east by the West of Cascades South path

Portland Area

Local Generation and Load

The Portland area has approximately 700 MW of local generation, including:

Portland/I-5 Area	Nameplate MW	Fuel Type	Owner
Bonneville Dam	1,310	Hydro	BPA/USACE
Beaver	490	Gas	Portland Gas & Electric
Centralia	1,400	Coal	TransAlta
Chehalis	520	Gas	PacifiCorp
Grays Harbor	650	Gas	Invenergy LLC
Mint Farm	320	Gas	Puget Sound Energy
Port Westward 1	380	Gas	Portland General Electric
Port Westward 2	230	Gas	Portland General Electric
River Road	260	Gas	Clark PUD
Mayfield	182	Hydro	Tacoma Power
Mossy Rock	378	Hydro	Tacoma Power
Merwin	135	Hydro	PacifiCorp
Swift	305	Hydro	PacifiCorp
Yale	145	Hydro	PacifiCorp
TOTAL	6,705		

The Portland load service area is both summer and winter peaking with high levels of residential, commercial, and industrial loads. The peak summer loads are due to high levels of air conditioning load. The peak winter loads are due to high levels of base board electric heating load. The Portland area load forecast is:

Portland Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
4022	4136	3910	3912	4129	4137	1.1	1.1

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Portland Area

In general, energy efficiency (EE) measures to minimize load growth in the greater Portland/Vancouver metro area and Willamette Valley and Southwest Washington (WILSWA)/I-5 Corridor area would reduce congestion on transmission paths and provide relief to the Portland load area. Most of the larger WILSWA utilities like PAC, PGE, Clark PUD and Cowlitz PUD account for existing and future energy efficiency savings in their submitted peak load forecasts. Portland customers are more likely to adopt energy saving or efficiency measures. However, much of the gains for EE have already been realized in part due to Portland customer's tendency for early adoption of EE and behavioral changes for reduced energy usage.

Some WILSWA utilities are pursuing pilot programs for demand response at commercial and retail locations (supermarkets, shopping centers, commercial office buildings) that could eventually contribute to peak load shaving. These programs are not completely mature; more data and information is required on the specifics of these programs, and if they are already being accounted for in the peak load forecast data supplied by the utilities. Redispatch of generation in the I-5 corridor is the single most effective non-wires solution to congestion in the Portland load area.

Annual load growth rates below 1.0 percent are often considered to be flat. Based on the very low projections for BPA customer load growth in Portland, non-wires projects are not required at this time in order to keep BPA customer load growth flat.

Proposed Plans of Service

Forest Grove – McMinnville 115 kV Line Upgrade

- Description: This project upgrades the Forest Grove – McMinnville 115 kV line.
- Purpose: This project improves operations and maintenance flexibility.
- Estimated Cost: $1,800,000
- Expected Energization: 2021

Carlton Upgrades

- Description: This project adds four additional circuit breakers at Carlton substation: two each at the 115 and 230 kV buses. Additionally, the Forest Grove–McMinnville 115kV line will be looped into the Carlton 115 kV bus, creating the Forest Grove–Carlton and Carlton–McMinnville 115 kV lines.
- Purpose: This project improves operations and maintenance flexibility.
- Estimated Cost: $4,400,000
- Expected Energization: 2021

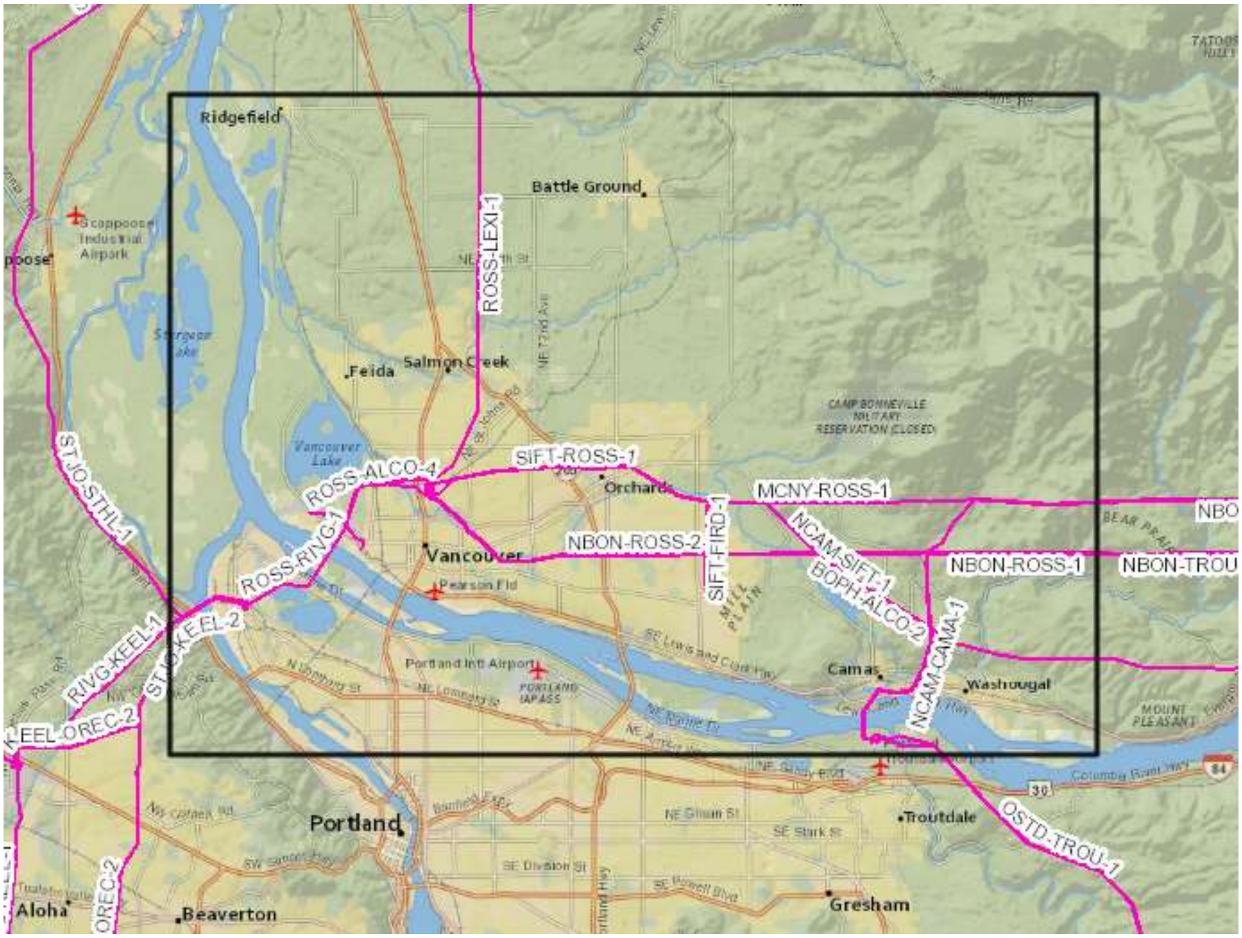
Recently Completed Plans of Service

Keeler 500/230 kV Transformer Re-termination

- Description: This project re-terminates the Keeler 500/230 kV transformer from the west bus section to the east bus section.
- Purpose: This project improves the balance of the loads and sources to the Keeler 230 kV bus.
- Estimated Cost: $1,600,000 (Compliance) $28,000,000 (Project)
- Expected energization: 2019

13.1.3 Vancouver Area

The Vancouver area transmission system serves Clark County PUD customers in Southwest Washington. This area extends north to the border of the Longview load service area and east to the Cascade Mountain Range. It is bordered on the south and west by the Columbia River. This includes the greater Vancouver, Washington area and the communities of Washougal, Camas, Ridgefield, La Center, and Battleground.



The customers in this area include:

- Clark Public Utilities (Clark)
- PacifiCorp (PAC)

The lines serving the area include:

- North Bonneville Ross 230 kV lines 1 and 2
- McNary-Ross 345 kV line
- Longview-Lexington-Ross 230 kV line
- Bonneville-Alcoa 115 kV line
- Bonneville-Sifton-Ross 115 kV line
- PAC Merwin-Cherry Grove-Hazel Dell-St Johns 115 kV line
- PAC/Clark Troutdale-Runyan-Sifton 115 kV line

Vancouver Area

Local Generation and Load

The local generation that supports the area load includes:

Portland/I-5 Area	Nameplate MW	Fuel Type	Owner
Bonneville Dam	1,310	Hydro	BPA/USACE
Beaver	490	Gas	Portland General Electric
Centralia	1,400	Coal	TransAlta
Chehalis	520	Gas	PacifiCorp
Grays Harbor	650	Gas	Invenergy LLC
Mint Farm	320	Gas	Puget Sound Energy
Port Westward 1	380	Gas	Portland General Electric
Port Westward 2	230	Gas	Portland General Electric
River Road	260	Gas	Clark PUD
Mayfield	182	Hydro	Tacoma Power
Mossy Rock	378	Hydro	Tacoma Power
Merwin	135	Hydro	PacifiCorp
Swift	305	Hydro	PacifiCorp
Yale	145	Hydro	PacifiCorp
TOTAL	**6,705**		

Vancouver Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
864	1082	790	1012	913	1017	2.9	0.1

Vancouver Area

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

To keep area load growth flat in the Vancouver area, load reduction of about nine MW per year is needed in the near term summer, five MW per year in the long term summer, nine MW per year in the near term winter, and six MW per year in the long term winter. A couple of options are available to defer future projects if needed. A non-wires plan to reduce load served out of several of CPUD's substations could significantly relax minimum generation requirements. In the longer term planning horizon, load reduction at these substations could potentially defer the need for a new shunt capacitor in the area. Also, a line and transformer in the PAC/CPUD area could potentially become a bottleneck for the area in the future, therefore a non-wires plan to reduce loading on these elements could potentially defer future projects.

Presently, there are no transmission reinforcements proposed in the area within the ten-year planning horizon.

Proposed Plans of Service

There are no proposed plans of service for this area.

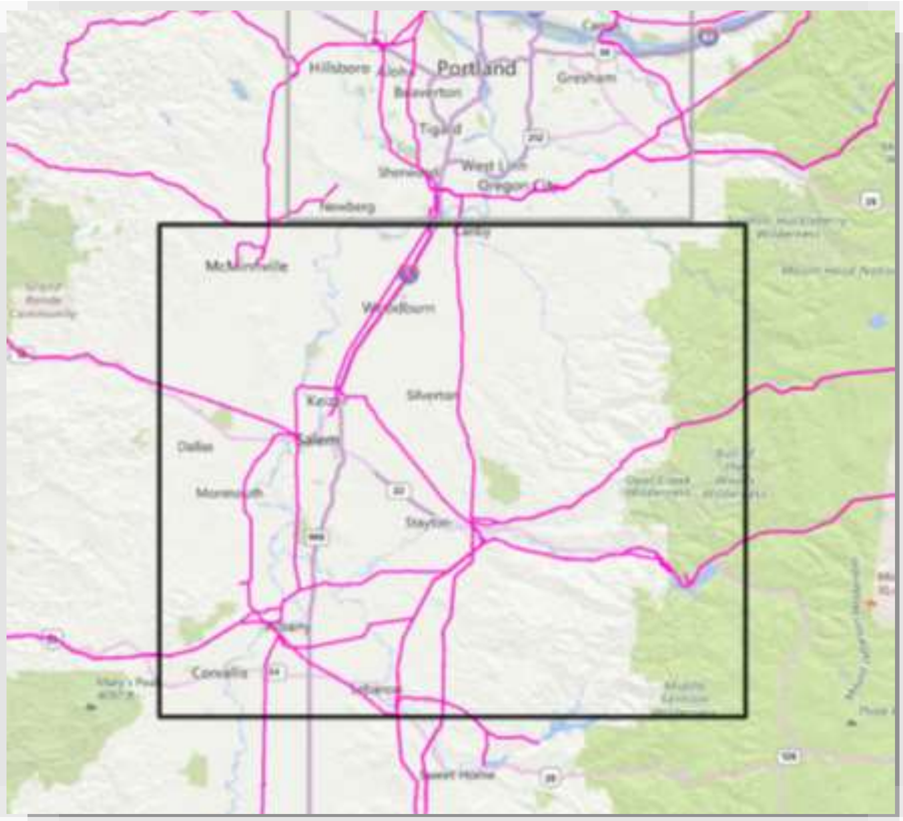
Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.4 Salem/Albany Area

The Salem/Albany load area serves the Central Willamette Valley. It is bordered on the north by the Portland load area and on the south by the Eugene load area. It is bordered by the Willamette National Forest to the east and by the central Oregon Coast Range to the west. It includes Polk, Benton, Marion and Linn counties.

The major population areas include Salem, Albany and Corvallis. Smaller communities include Monmouth, Independence, Silverton, Stayton, and Lebanon.



The customers in this area include:

- Portland General Electric in the Salem Area
- PacifiCorp in the Albany, Corvallis, Lebanon Areas
- City of Monmouth
- U.S. Bureau of Mines located in Albany, Oregon
- Several Electric Cooperatives: Western Oregon, Salem Electric, and Consumers Power Inc. Emerald PUC serving the rural areas

The load area is served by the following major transmission paths or lines:

- From the east by the Big Eddy-Chemawa 230 kV line
- From the north by the (PGE) McLoughlin-Bethel 230 kV line and the Pearl-Marion 500 kV line 1

Salem/Albany Area

Local Generation and Load

The local generation is mostly hydroelectric generation on the north and south forks of the Santiam River.

- USACE Foster Dam (22 MW)
- USACE Green Peter Dam (92 MW)
- USACE Detroit Dam (120 MW)
- Big Cliff Dam (22 MW)
- Consumer's Power, Inc. Adair Generation (5.6 MW)

Salem/Albany Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
840	895	880	973	907	952	0.6	-0.4

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

In order to maintain flat growth in the Salem/Albany area 4.3 MW per year and 4.4 MW per year would have to be reduced in the summer and winter. The Salem/Albany area consists of residential, commercial, and agriculture. This is a largely rural area and there is little industrial load. There is an existing energy storage resource near the Market/Oxford area. PGE's Salem Smart Power Center is a 5 MW battery.

Proposed Plans of Service

There are no proposed plans of service for this area.

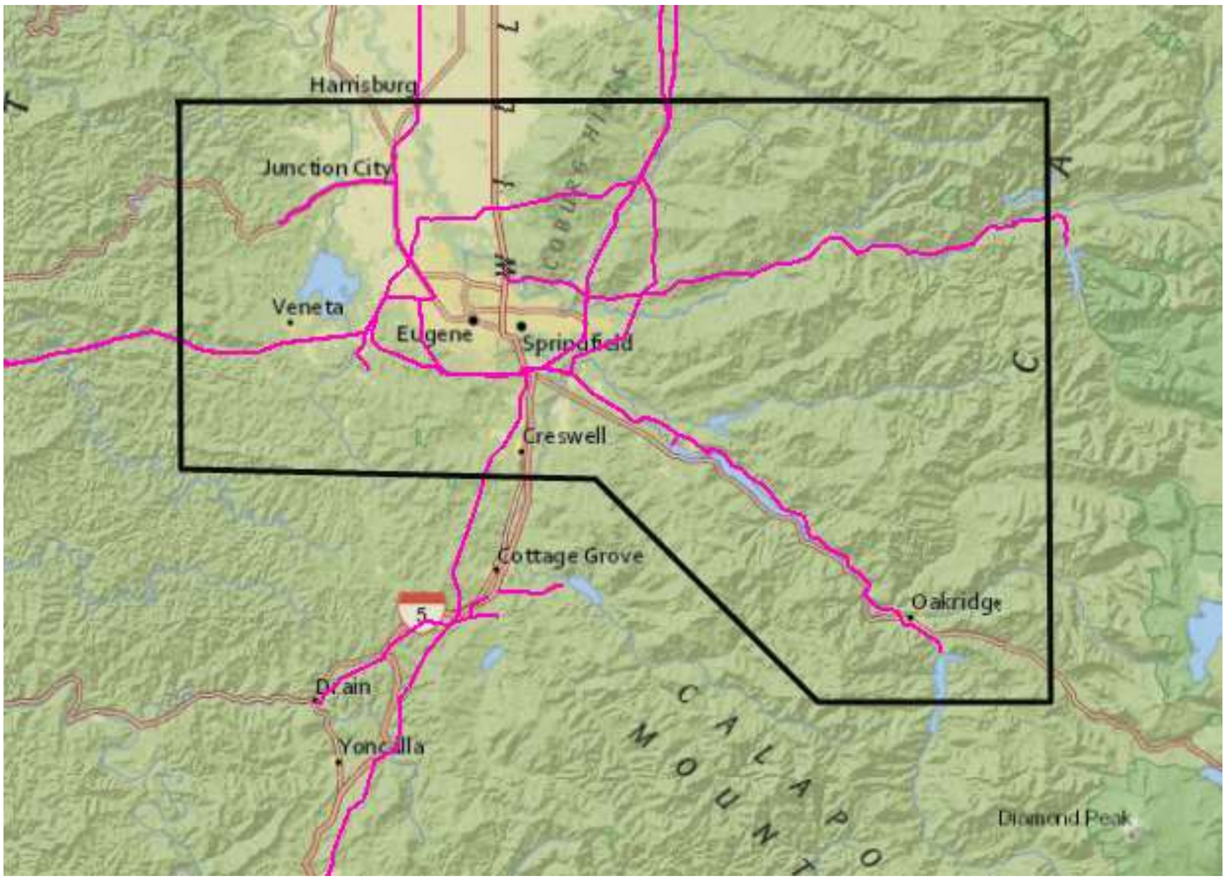
Recently Completed Plans of Service

Salem-Chemawa 115 kV Line Disconnect Switches

- Description: This project eliminates the bottleneck on the Chemawa-Salem 115 kV line.
- Purpose: The system assessment showed a need for the line upgrade to maintain reliable load service to the Salem area.
- Estimated Cost: $1,200,000
- Expected Energization: 2019

13.1.5 Eugene Area

The Eugene Area includes the cities of Eugene and Springfield in western Oregon as well as the surrounding communities. This load area includes the Central Willamette Valley in Oregon's Lane County. It is bounded by Willamette National Forest on the east and the coast range on the west. It is bounded by the Salem/Albany load area to the north and the South Oregon Coast area to the south and west of Eugene. The major population areas include cities of Eugene and Springfield, and the communities of Cheshire, Junction City, Harrisburg, Walterville, Pleasant Hill and Oakridge.



The customers in this area include:

- PacifiCorp (PAC)
- Eugene Water and Electric Board (EWEB)
- Springfield Utility Board (SUB)
- Emerald Public Utility District (Emerald)
- Several Electric Cooperatives: Blachly-Lane, Lane Electric, Douglas Electric, Coos-Curry, and Consumers Power serving the rural areas

The load area is served by the following major transmission paths or lines:

- From the Marion-Alvey 500 kV line and Marion-Lane 500 kV line
- From the south by the Alvey-Dixonville 500 kV line

Eugene Area

Local Generation and Load

The local generation in this area includes hydroelectric generation on the McKenzie and Willamette Rivers and other generation as follows:

- EWEB Carmen/Trailbridge (93.3 MW)
- USACE Cougar (28 MW)
- EWEB Weyco (37.7 MW)
- EWEB Seneca (19.8 MW)
- EWEB Leaburg (13.8 MW)
- EWEB Walterville (9.7 MW)
- USACE Lookout Point (138 MW)
- USACE Hills Creek (34 MW)
- USACE Dexter (16 MW)

Loads in this area are primarily residential and commercial, with a smaller industrial component. The Eugene area load forecast is:

Eugene Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
602	895	609	775	727	780	3.6	0.1

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Eugene Area

Proposed Plans of Service

Alvey 115 kV Bus Sectionalizing Breaker Addition

- Description: This project adds a 115 kV bus sectionalizing breaker at Alvey Substation.
- Purpose: This project improves operations and maintenance flexibility
- Estimated Cost: $8,000,000
- Expected Energization: 2022

Lookout Point – Alvey No. 1 and 2 Transfer Trip Addition

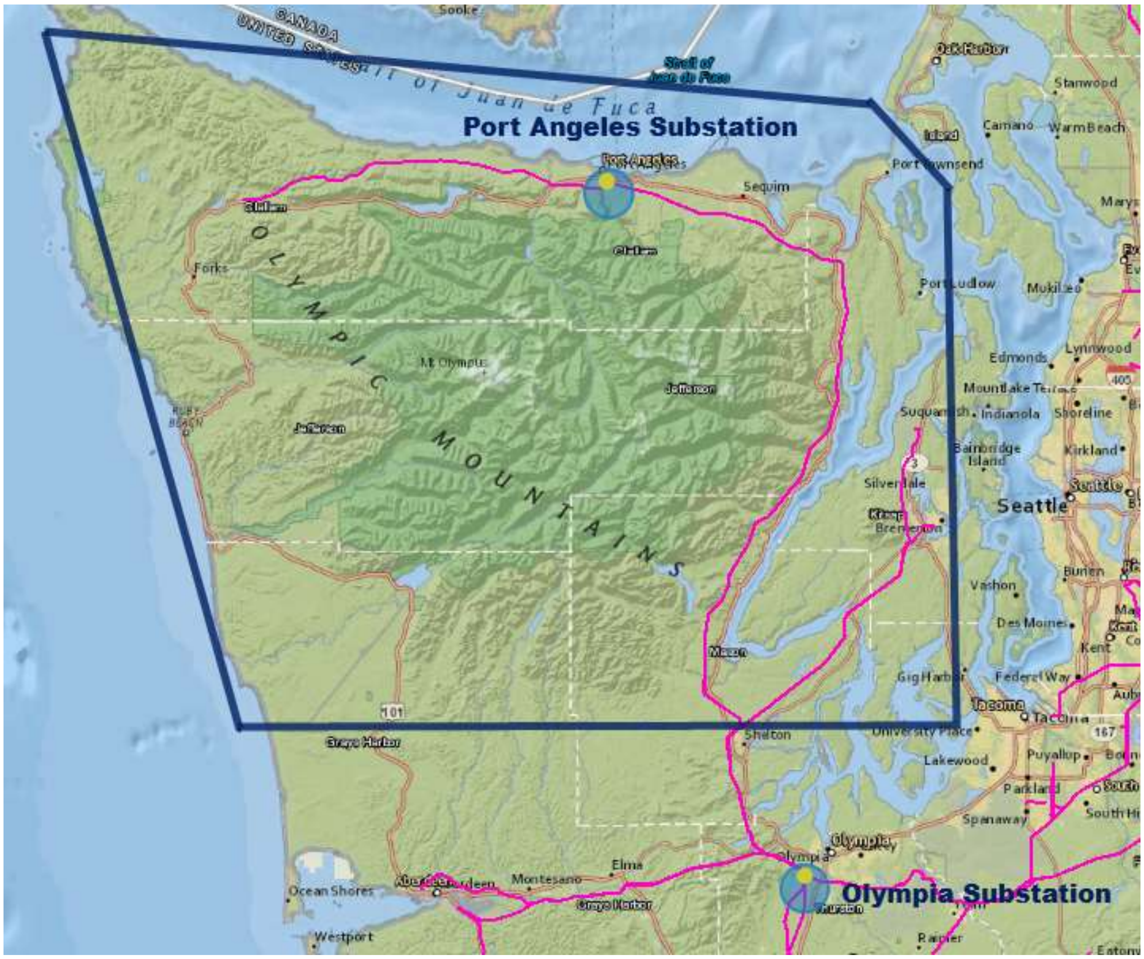
- Description: Installation of Transfer Trip on the Alvey – Lookup 115 kV Lines 1 and 2 is needed to prevent local generation from going out of step following three-phase line faults near Alvey Substation.
- Purpose: This project is required to maintain reliable load service to the area.
- Estimated Cost: $400,000
- Expected Energization: 2022

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.6 Olympic Peninsula Area

The Olympic Peninsula in Washington State is a long radial system extending about 110 miles from BPA's Olympia Substation northwest to BPA's Port Angeles substation. This area includes the Olympic Peninsula north and west of Olympia. Included within this area are Clallam, Mason, Kitsap and the western portion of Jefferson counties. The primary communities served include Shelton, Bremerton, and Port Angeles, as well as the US Navy in the Bremerton area. The smaller communities include Potlatch, Hoodsport, Quilcene, Fairmount, Duckabush, and Sequim.



The customers in this area include:

- Puget Sound Energy
- City of Port Angeles
- Clallam County Public Utility District
- Mason Public Utility District 1 and 3
- US Navy

The load area is served by the following major transmission paths or lines:

- Satsop-Shelton 230 kV line
- Three Olympia-Shelton 230 kV lines
- Two Olympia-Shelton 115 kV lines

Olympic Peninsula Area

Local Generation and Load

There is no generation connected directly to the load area, although there is some generation at Mason that serves the Tacoma area and the Grays Harbor plant located south of the load area.

The Olympic Peninsula area load forecast is:

Olympic Peninsula Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
742	1284	852	1404	827	1356	-0.6	-0.7

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Proposed Plans of Service

Kitsap 115 kV Shunt Capacitor Relocation

- Description: This project moves one group of 115 kV shunt capacitors from the south bus to the north bus section at Kitsap substation.
- Purpose: This project is required to maintain voltage schedules on the Kitsap Peninsula transmission system.
- Estimated Cost: $4,000,000
- Expected Energization: 2022

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.7 Tri-Cities Area

The Tri-Cities Load Area study covers loads in Benton and Franklin counties in Washington. The Tri-Cities area is in South Central Washington and includes the three major cities of Pasco, Kennewick, and Richland along with surrounding communities as far as Grandview and Prosser to the west, Burbank and Wallula to the east, and Plymouth and Paterson to the south. This load area includes significant irrigation loads served by Big Bend Electric, Benton PUD, and Benton REA. (Note: The Boardman area was not included in the Tri-Cities area this year. The Boardman area was studied independently. Transmission needs identified for the Boardman area are provided in separate section below.)

The customers in this area include:

- Benton County Public Utility District
- Benton Rural Electric Association
- Big Bend Electric Cooperative
- City of Richland
- Columbia Rural Electric Association
- Franklin County Public Utility District
- U.S. Bureau of Reclamation (South Columbia Basin Irrigation District)
- U.S. Department of Energy (Richland Operations)

The load area is served by the following major transmission paths or lines:

- From the east by:
    - the Lower Monumental-McNary 500 kV line tapped at Sacajawea with a 500/115 kV transformer
- From the north by:
    - the Midway-Benton 230 kV line and Benton 230/115 kV transformer
    - the Midway-Benton 115 kV line
    - the Midway-Ashe 230 kV lines through Hanford, the Ashe-White Bluffs 230 kV line and White Bluffs 230/115 kV transformer
- From the south by:
    - the McNary-Franklin 230 kV line and Franklin 230/115 kV transformer
    - the McNary-Badger Canyon 115 kV line
    - the Horse Heaven 230/115 kV transformer
- From the west by:
    - the Grandview-Red Mountain 115 kV line

Tri-Cities Area

Local Generation and Load

The local generation is hydroelectric and wind generation. The nuclear Columbia Generating Station (1100 MW) is physically located in the Tri-Cities area, but is not electrically connected to the local load area. Therefore it is not considered part of the local generation.

- USACE Ice Harbor Hydro (Snake River; 700 MW)
- USBR Chandler Hydro (Yakima River; 12 MW)
- Scooteney, Glade & Ringold Hydro (Irrigation system; 11 MW total)
- NextEra Energy Resources Stateline Wind (90 MW)
- Energy NW Nine Canyon Wind (90 MW)

Tri-Cities Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1158	1007	1342	1089	1404	1137	0.9	0.9

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

A non-wires assessment team was formed in 2019 to evaluate potential non-wires solutions for the Tri-Cities area. The team concluded that non-wires solutions were not cost-effective in delaying or mitigating the need for the proposed wires projects in the area. Specifically, there was not enough demand response to mitigate contingencies, there were no firm resource options for local generation, and batteries are too expensive of an option based on needed siting and flows.

Tri-Cities Area

Proposed Plans of Service

McNary-Paterson Tap 115 kV Line

- Description: This project adds a new 115 kV PCB at McNary 115 kV substation and adds approximately 2 miles of new 115 kV line.
- Purpose: This upgrade is needed to provide reliable load service to the Tri-Cities area.
- Estimated Cost: $4,600,000
- Expected Energization: 2022

Red Mountain – Horn Rapids 115 kV Line Reconductor

- Description: This project is to reconductor the Red Mountain – Horn Rapids 115 kV section of BPA's Red Mountain – White Bluffs 115 kV transmission line to mitigate a bottleneck impeding the ability to serve load.
- Purpose: The purpose of this project is to mitigate a bottleneck impeding the ability to serve load.
- Estimated Cost: $3,700,000
- Expected Energization: 2022

Jones Canyon 230 kV Shunt Reactor Addition

- Description: This project adds a 230 kV shunt reactor (40 Mvar) at Jones Canyon Substation.
- Purpose: This project is required to maintain voltage schedules in the area during light load conditions.
- Estimated Cost: $3,300,000
- Expected Energization: 2022

Richland-Stevens Drive 115 kV Line

- Description: This project adds a new 115 kV line terminal and three miles of new 115 kV line.
- Purpose: This upgrade is needed to provide reliable load service to the Tri-Cities area.
- Estimated Cost: $4,000,000
- Expected Energization: 2024

Cost and schedule will be refined as the project progresses through the scoping process.

South Tri-Cities Reinforcement

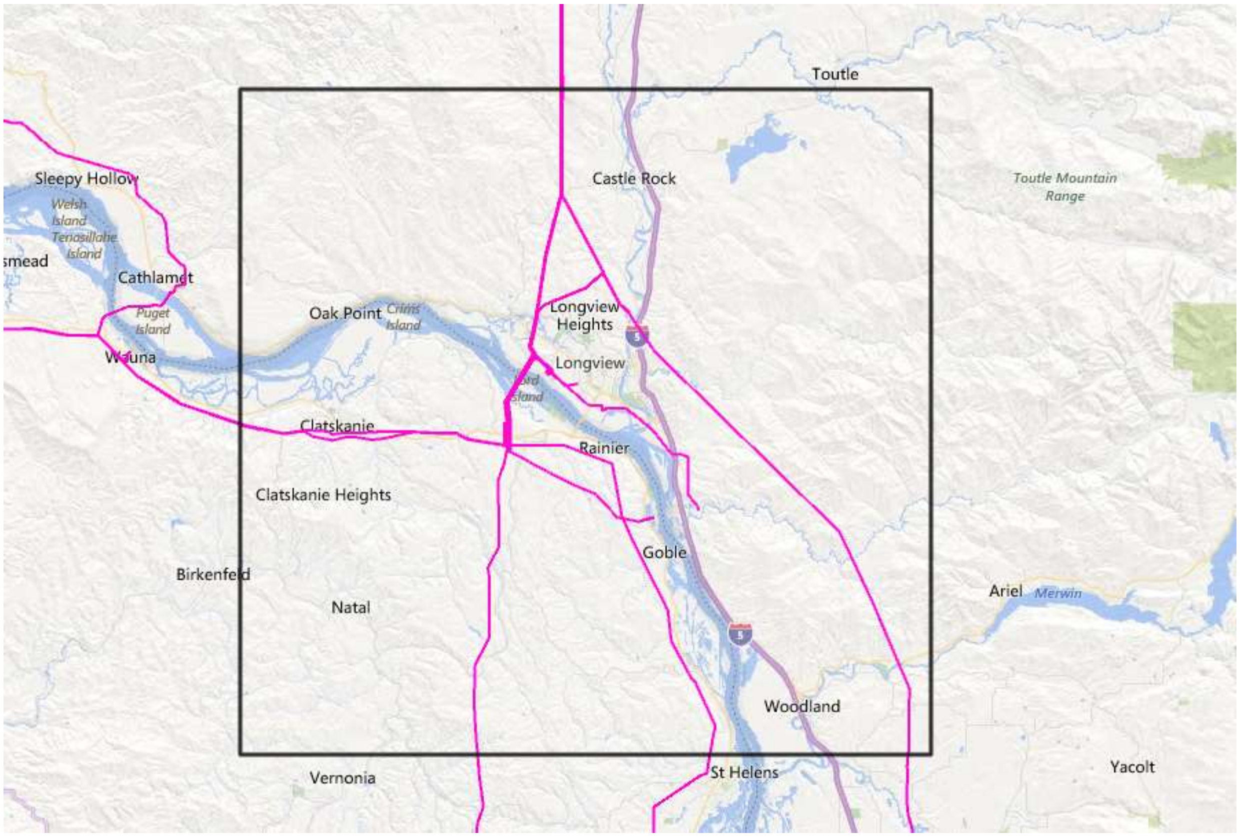
- Description: This project builds a 500 kV substation connecting the Ashe-Slatt #1 500 kV line or Ashe-Marion #2 500 kV line to the 115 kV local area system, either at Red Mountain or at Badger Canyon. Both alternatives are being scoped.
- Purpose: This project is part of the longer team plan for the Tri-Cities area and is not needed for compliance with the NERC TPL Standard.
- Estimated Cost: To be determined
- Expected Energization: To be determined
  Cost and schedule will be refined as the project progresses through the scoping process.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.8 Longview Area

This area includes Cowlitz County in Washington State. The major population areas include Longview, Washington as well as the communities of Kelso, Kalama, Castle Rock, and Woodland, Washington.



The customers in this area include:

- Cowlitz Public Utility District
- PacifiCorp (PAC)

The load area is served by the following major transmission paths or lines.

- Longview-Allston 230 kV lines 1, 2 and 3
- Longview-Allston 115 kV line 4
- The Chehalis-Longview 230 kV lines 1 and 2
- Ross-Lexington 230 kV line
- PAC Merwin-Cardwell 115 kV line

Longview Area

Local Generation and Load

The local generation that supports the area load includes:

- Mint Farm (270 MW)
- PAC and Cowlitz Swift Hydro (280 MW)
- PAC Merwin and Yale Hydro (235 MW)
- Weyerhauser Company (80MW)
- Longview Fiber (55MW)

Longview Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
646	830	678	873	674	876	-0.1	0.1

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. For areas that have performance deficiencies and corrective action plans identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For those areas with no recommended project(s), the potential for non-wires measures to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

For this area, the load reduction required to keep the peak load growth flat is five MW per year in summer and six MW per year in winter. A Longview non-wire assessment found 79 customers with demand of greater than 250 kW in the Longview 115 kV network may be candidates for demand response. The largest load categories (greater than nine MW) are chemical plants, grain elevators, steel fabrication, and wood products. There is significant technical potential of energy efficiency in addition to that which is already planned and included in the forecast. However, costs may be a barrier.

Proposed Plans of Service

Longview 230/115 kV Transformer Addition

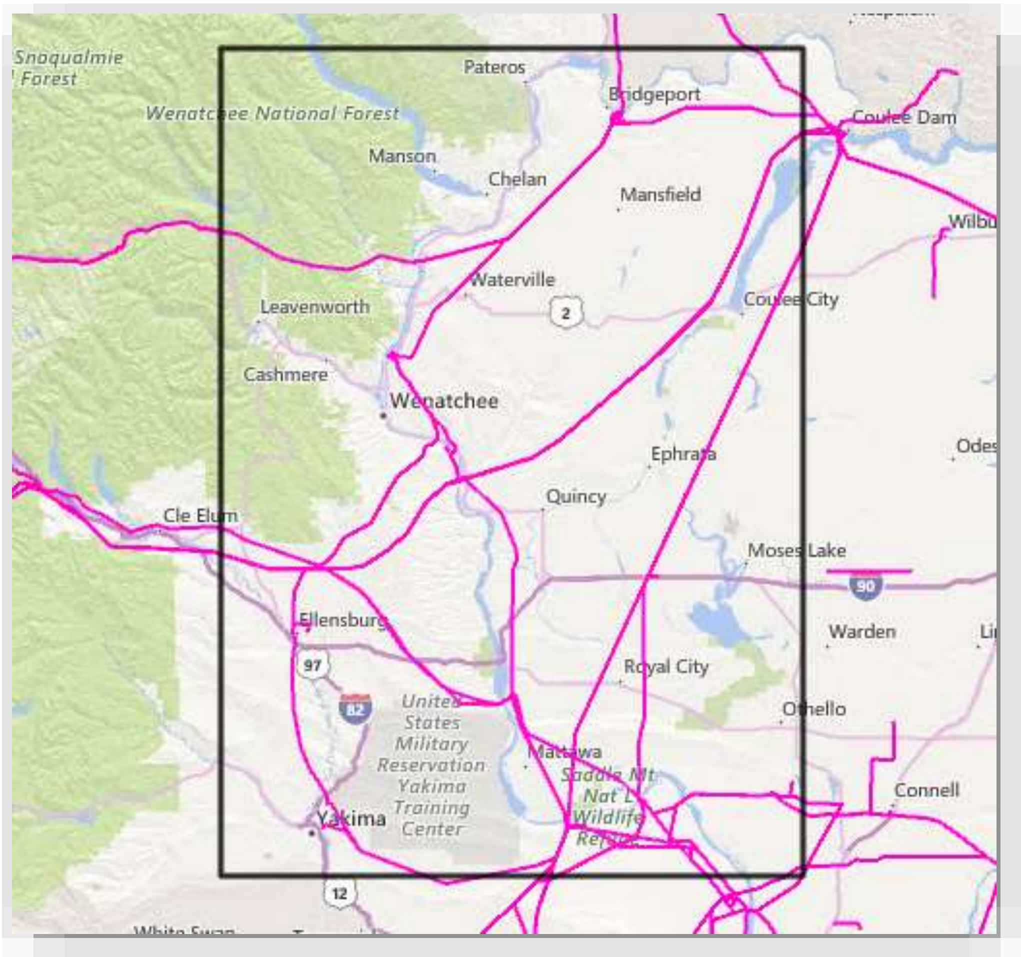
- Description: This project installs a second 230/115 kV transformer bank at the Longview Substation in the Longview area. To make room for the new transformer, the existing 230/13.8 kV transformer bank no. 5 will be removed. A new 230 kV bus sectionalizing breaker on the Longview 230 kV main bus section will be added.
- Purpose: This project is required to maintain reliable load service to the Longview area. The breaker addition will resolve the issues caused by a 230 breaker failure outage at Longview.
- Estimated Cost: $15,000,000
- Expected Energization: 2022

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.9 Mid-Columbia Area

The Mid-Columbia (Mid-C) area includes the Columbia Basin area of central Washington, excluding the Tri-cities area (Kennewick, Pasco, and Richland), which is considered a separate load area. The Mid-C area extends from Moses Lake in Grant county, east to Leavenworth in Chelan county, Ellensburg in Kittitas county and Yakima in Yakima county to the west. It extends from Chelan and Douglas Counties to the north to Sunnyside in the south.



The customers in this area include:

- Chelan County PUD (Chelan)
- Grant County PUD (Grant)
- Douglas County PUD (Douglas)
- Avista energy (Avista)
- Kittitas County PUD (Kittitas)
- City of Ellensburg
- Benton REA (BREA)
- PacifiCorp (PAC)

The load area is served by the following major transmission paths or lines:

- From the northeast by two Grand Coulee-Columbia 230 kV lines, a Grand Coulee-Rocky
- Ford-Midway 230 kV line and a Grand Coulee-Midway 230 kV line
- From the south by the Midway-Big Eddy and the Midway-North Bonneville 230 kV lines

Mid-Columbia Area

Local Generation and Load

The local generation that supports the area load includes three classes:

Hydroelectric generation – There are 5 major hydroelectric plants on the Columbia River, including:

- Douglas Wells Dam (840 MW)
- Chelan Rocky Reach Dam (1287 MW)
- Chelan Rock Island Dam (660 MW)
- Grant Wanapum Dam (1038 MW)
- Grant Priest Rapids Dam (955 MW)

Wind generation – There are 2 wind farms; these include:

- Puget Sound Energy Wild Horse (273 MW)
- Horizon Kittitas Valley Wind (101 MW)

Other Generation – The other local generation includes:

- Chelan Falls Hydroelectric Project (59 MW)
- Grant Quincy Chute Hydroelectric (9.4 MW)
- SCL Summer Falls Power Plant (92 MW)
- USBR Roza Power Plant Yakima Project (13 MW)
- Grant Potholes East Canal (6.5 MW)

The Mid-Columbia (Mid-C) load area is divided into three sub-areas; west, north, and east. To the west is the Yakima County load served by PacifiCorp, and load served by BPA customers in the Ellensburg and surrounding area (load served by the Columbia-Ellensburg, Ellensburg-Moxee, and Moxee-Midway 115 kV lines). To the north is load served by Douglas and Chelan County PUD. To the east is load served by Grant County PUD and a pocket of Avista Mid-C load located in Central Washington connected to Chelan and Grant PUD. The Mid-C area load is a combination of traditional residential load and agricultural load.

Mid-Columbia Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
2373	2456	2563	2897	2550	3033	-0.1	0.9

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Mid-Columbia Area

The Mid-Columbia (Mid-C) area has more generation than load. Load is growing at a rate of approximately 2.3 percent a year, which is approximately 50 MW a year. The transmission system must deliver the local generation output to local load areas and also reliably transfer surplus generation to the main grid for export out of the area.

The major Mid-C hydroelectric projects are typically divided into the upper Mid-C including Wells, Rocky Reach, and Rock Island which are north of the local Mid-C BES bottlenecks; and the lower Mid-C including Wanapum and Priest Rapids which are south of these bottlenecks. The transmission constraints can be managed by re-dispatching generation between these two Mid-C area hydro generation centers.

The various Mid-C generation patterns have a greater impact on the Mid-C area transmission system performance than load growth. The Mid-C generation must be operated to mitigate major overloads, ensuring unconstrained flow of power transfers from the major dams to the major substations in the area. The hydro project owners operate the Mid-Columbia hydro facilities to prevent line overloads. The capability of re-dispatching generation allows the Mid-C system to continue operating within facility ratings, which would only be possible otherwise by building new lines. Shifting generation from Upper Mid-C units to Lower Mid-C units is very effective in reducing the north to south to flow. Once the available capacity of the Lower Mid-C units is used the generation at Upper Mid-C units can be shifted to Grand Coulee units to further relieve the transmission constraints. Moving generation farther north from Columbia substation reduces the flow through Columbia creating a favorable transmission loading condition in anticipation of a potential outage.

As each PUD in the Mid-Columbia area plans to meet the growing demands in its load area, BPA works with all stakeholders and the PUDs to pursue non-wire options before embarking on building new facilities in the area.

Proposed Plans of Service

Northern Mid-Columbia Area Reinforcement

- Description: This is a joint project between BPA, Grant PUD, Douglas PUD, and Chelan PUD. This project will result in a new Columbia-Rapids 230 kV line.
- Purpose: This project is required to maintain reliable load service to the Northern Mid-Columbia area.
- Estimated Cost: $13,300,000
- Expected Energization: 2021

Columbia 230 kV Bus Tie and Bus Sectionalizing Breaker Addition (Combined with project above.)

- Description: This project adds a new 230 kV bus tie breaker and 230 kV bus sectionalizing breaker at Columbia Substation.
- Purpose: This project improves operational and maintenance flexibility at Columbia Substation.
- Estimated Cost: See above
- Expected Energization: 2021

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.10 Central Oregon/Alturas Area

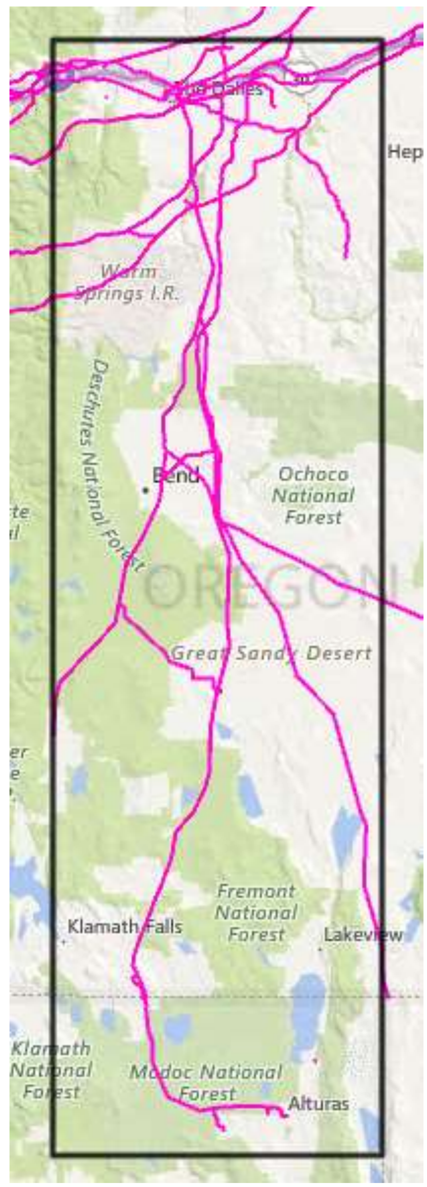
Central Oregon

The Central Oregon area includes the communities of Madras to the north, the cities of Redmond and Bend to the west, the city of Prineville to the east and the city of La Pine and community of Sun River to the south. It includes Jefferson and Deschutes counties in Oregon.

The customers in the Central Oregon area include:

- PacifiCorp
- Central Electric Cooperative
- Midstate Electric Cooperative

The Central Oregon load area is served by the following major BPA transmission path or lines:



- Big Eddy-Redmond 230 kV line
- Two 500/230 kV transformers at Ponderosa and the BPA Ponderosa-Pilot Butte 230 kV line
- Pilot Butte – La Pine 230 kV line

Alturas

The Alturas area includes the northeast corner of Modoc County in northern California including the communities of Canby and Alturas.

The customers in the northern California area include:

- Surprise Valley Electrification Corporation
- PacifiCorp

The Alturas load area is served by the following major, BPA transmission path or lines:

- Malin 500/230 kV Transformer and a Malin-Canby-Hilltop 230 kV line with a Canby 230/69 kV transformer
- Hilltop-Warner 230 kV terminated with 230/115 kV Transformer
- La Pine- Chiloquin 230 kV line

Central Oregon/Alturas Area

Local Generation and Load

The only significant local generation in the area is PGE's Pelton Round Butte Project. This is a hydroelectric project consisting of three hydroelectric plants: Round Butte Dam (338 MW), Pelton Dam (110 MW), and a reregulating dam (20 MW). The generation is interconnected at PGE's Round Butte Substation.

Central Oregon/Alturas Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
532	687	530	697	605	789	2.7	2.5

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. For areas that have performance deficiencies and corrective action plans identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For those areas with no recommended projects(s), the potential for non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

The Central Oregon and Northern California load areas meet the planning performance requirements for the near term and long term planning horizon. The Central Oregon and Northern California load areas will also meet the expected load growth and expected transfers for the ten-year planning horizon assuming the projects and corrective action plans are implemented according to the proposed timelines. No major changes to the area since the previous system assessment were identified.

Proposed Plans of Service

LaPine 115 kV Circuit Breaker Additions

- Description: This project adds two 115 kV circuit breakers for the low side of the transformer banks 1 and 2 as well as a 115 kV bus tie breaker.
- Purpose: This project improves operations and maintenance flexibility.
- Estimated Cost: $280,000 (O&M)
- Expected Energization: 2020

Central Oregon Series Capacitor (Included in the California-Oregon Intertie Section.)

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.11 Southwest Washington Coast Area

The Southwest Washington Coast area is comprised of Wahkiakum county, Pacific county, western Lewis county, and southern Grays Harbor county in Washington. It is bordered on the east by Interstate 5 and the west by the Pacific Ocean. It is bordered on the north by the Olympic National Forest and on the south by the Columbia River. The main communities served include Aberdeen, the Raymond/South Bend area, and the communities on the Long Beach Peninsula. Smaller communities include Cosmopolis, Pe Ell, and Naselle. Customers in the area include Grays Harbor County PUD (GHPUD), Pacific County PUD, and Wahkiakum County PUD.

The customers in this area include:

- Grays Harbor Public Utility District (including some industrial load)
- Pacific County Public Utility District No. 2
- Wahkiakum County Public Utility District
- Lewis County Public Utility District

The load area is served by the following major transmission paths or lines:

- Aberdeen-Satsop 230 kV lines 2 and 3
- Olympia-South Elma 115 kV line
- Chehalis-Raymond 115 kV line 1
- Naselle Tap to the Allston-Astoria 115 kV line 1

Southwest Washington Coast Area

Local Generation and Load

Local generation serving the load area includes:

- Wynooche (18.7 MW)
- Weyerhaeuser (15.8 MW)
- Sierra (7.9 MW)

Southwest Washington Coast Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
184	353	286	421	300	430	1.0	0.4

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. For areas that have performance deficiencies and corrective action plans identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For those areas with no recommended projects(s), the potential for non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

There are no known demand response programs, distributed energy resource or Smart Grid projects in the area. In order to keep peak load growth flat, load reduction would be required across the area in addition to the energy efficiency improvements assumed in the forecasts. The load reduction required to keep the peak load flat is about five MW per year in winter.

Proposed Plans of Service

Holcomb-Naselle 115 kV Line Upgrade

- Description: This line will be rebuilt with larger conductor as part of the wood pole replacement program.
- Purpose: This project is required to maintain reliable load service to the Southwest Washington Coast area.
- Estimated Cost: The cost of this project is included as part of the overall wood pole replacement program. $10,400,000
- Expected Energization: 2021
- This project is experiencing delays due to environmental requirements.

Southwest Washington Coast Area

Aberdeen Tap to Satsop Park – Cosmopolis 115 KV Line Upgrade

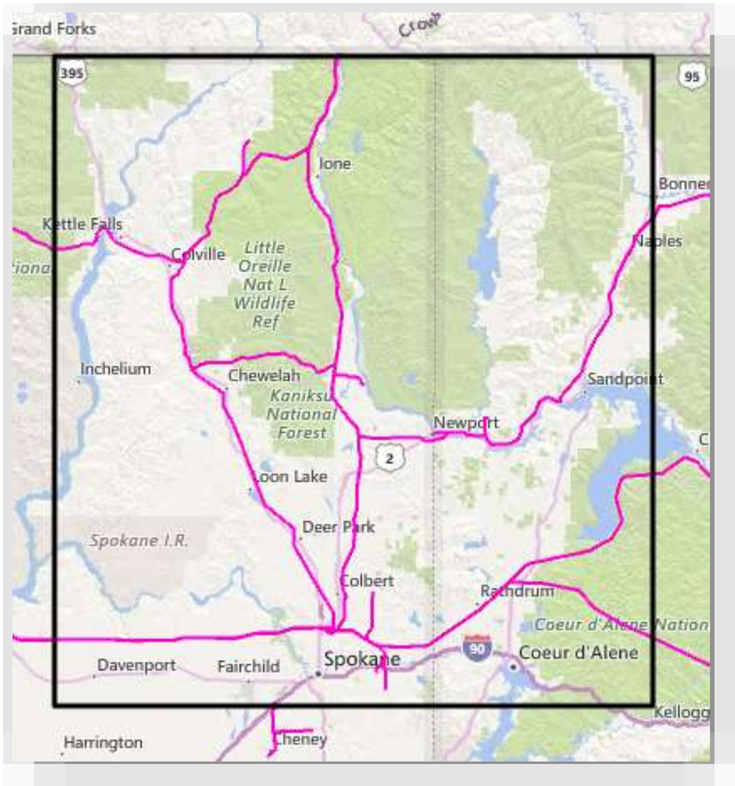
- Description: Rebuild the section between Aberdeen Tap and Structure 1/3 (0.06 mi) to remove bottle neck.
- Purpose: This project is required to maintain reliable load service to the Southwest Washington Coast area.
- Estimated Cost: $191,000
- Expected Energization: 2022

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.12 Spokane/Colville/Boundary Area

This area is located in eastern Washington State. It extends north to include the Colville Valley and east to include Newport, Washington. This load area includes the greater Spokane, Washington area as well as Colville Valley to the north including the communities of Colville and Chewelah. This area also includes Newport, Washington to the east, as well as Pend Oreille, Stevens and Spokane Counties.



The customers in this area include:

- Avista
- Inland Power and Light
- West Kootenai Power and Light
- Pend Oreille PUD
- Ponderay Newsprint Company

The load area is served by the following major transmission paths or lines:

- Bell-Boundary 230 kV lines 1 and 2
- Usk-Boundary 230 kV line
- Taft Bell 500-kV line
- Bell-Lancaster 230 kV line
- Avista Lancaster-Boulder 230 kV line
- Avista Benewah-Boulder 230 kV line
- Avista Rathdrum-Boulder 230 kV line
- Grand Coulee-Bell 500 kV line
- Three Grand Coulee-Bell 230 kV lines
- Grand Coulee-Westside 230 kV line

Spokane/Colville/Boundary Area

Local Generation and Load

Local generation serving the load area includes:

Spokane/Colville Generation	Fuel	Maximum MW	Owner
Boundary	Hydro	1040	Seattle City Light
Box Canyon	Hydro	90	Pend Oreille's
Albeni Falls	Hydro	48	USACE
Long Lake	Hydro	88	Avista
Little Falls	Hydro	32	Avista
Dworshak	Hydro	458	USACE
Boulder	Hydro	25	Avista
Post Street	Hydro	10	Avista
Monroe	Hydro	16	Avista
Spokane Waste	Steam Turbine	22	City of Spokane's
Northeast	Gas Turbine	68	Avista
Up River	Hydro	18	City of Spokane
Nine Mile	Hydro	24	Avista
Post Falls	Hydro	18	Avista
Kettle Falls	Steam Turbine	52	Avista
Total		2009	

Spokane/Colville/Boundary Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
896	924	828	858	891	893	1.5	0.8

Spokane/Colville/Boundary Area

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. For areas that have performance deficiencies and corrective action plans identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For those areas with no recommended projects(s), the potential for non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

The area is primarily residential with a smaller amount of commercial and industrial.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

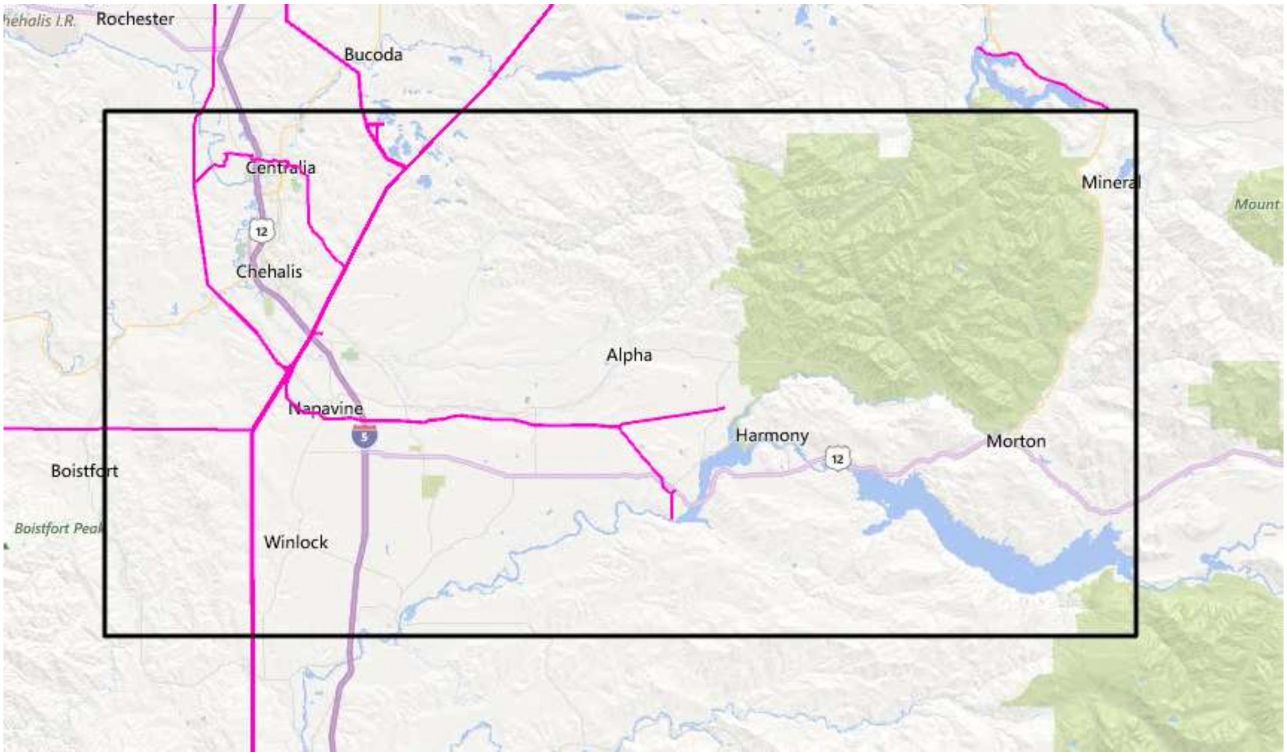
There are no proposed projects for this area at this time.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.13 Centralia/Chehalis Area

The Centralia/Chehalis area includes the cities of Chehalis and Centralia, Washington and the communities within Lewis County in Washington. It consists of a 69 kV transmission loop served out of Chehalis Substation. Chehalis Substation also provides service to Lewis County PUD's Corkins 69 kV Substation and provides support to Raymond and Naselle Substations on the southwest Washington coast.



The customers in this area include:

- Centralia City Light
- Lewis County PUD

The load area is served by the following major transmission paths or lines:

- Chehalis- Olympia 230 kV line 1
- Chehalis- Covington 230 kV line 1
- Chehalis-Raymond 115 kV line 1

Centralia/Chehalis Area

Local Generation and Load

Local generation serving the load area includes:

Generation	Fuel	Maximum MW	Owner
Mossy Rock	Hydro	378	Tacoma Power
Mayfield	Hydro	182	Tacoma Power
Cowlitz	Hydro	70	Lewis County PUD
Packwood	Hydro	28	Energy Northwest
Yelm	Hydro	10	City of Centralia

Centralia/Chehalis Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
134	235	169	263	173	270	0.5	0.5

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. For areas that have performance deficiencies and corrective action plans identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For those areas with no recommended projects(s), the potential for non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Proposed Plans of Service

Silver Creek Substation Reinforcements

- Description: This project adds a 230 kV breaker to separate the east and west 230 kV busses and adds a 69 kV circuit breaker on the low side of the 230/69 kV transformer.
- Purpose: This project increases the reliability and facilitates maintenance of the station.
- Estimated Cost: $2,200,000
- Expected Energization: 2022

Recently Completed Plans of Service

Paul Reactor Addition

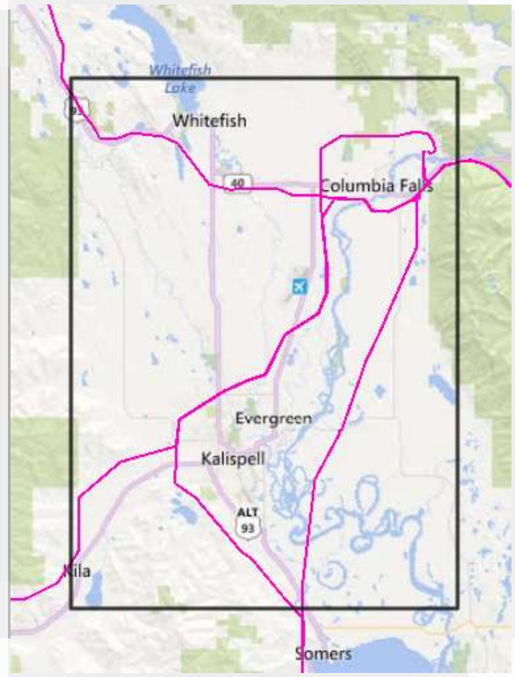
- Description: This project adds a reactor at the Paul substation.
- Purpose: This addition is needed to maintain reliability in the Centralia/Chehalis area.
- Estimated Cost: $1,700,000
- Expected Energization: 2019

13.1.14 Northwest Montana Area

This area covers loads in Flathead and Lincoln counties in Montana. It includes the Flathead Valley area of northwest Montana including the communities of Kalispell and Columbia Falls.

The customers in this area include:

- Flathead Electric Cooperative
- Northwestern Energy
- Lincoln Electric Cooperative
- U.S. Bureau of Reclamation (USBR)



The Northwest Montana load area is served by the following major transmission paths or lines:

- Hungry Horse – Columbia Falls 230 kV line 1
- Hungry Horse – Conkelley 230 kV line 1
- Columbia Falls – Kalispell 115 kV line 1
- Columbia Falls – Trego 115 kV line 1
- Columbia Falls – Conkelley 230 kV line 1
- Columbia Falls – Flathead 230 kV line 1
- Libby-Conkelley 230 kV line 1

Local Generation and Load

Local generation serving the load area includes:

- Avista Rathdrum (154 MW)
- Avista Cabinet Gorge (263 MW)
- Cogentrix Energy Lancaster (270 MW)
- PPL Global Kerr (194 MW)
- PPL Global Colstrip (2094 MW)
- USACE Noxon (488 MW)
- USACE Libby (600 MW)

Northwest Montana Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
259	354	268	373	284	399	1.2	1.4

Northwest Montana Area

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

For this area, load growth forecasts are expected to stay flat or increase no more than 1.1 percent per year beyond the long term planning horizon.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

Conkelley Substation Retirement

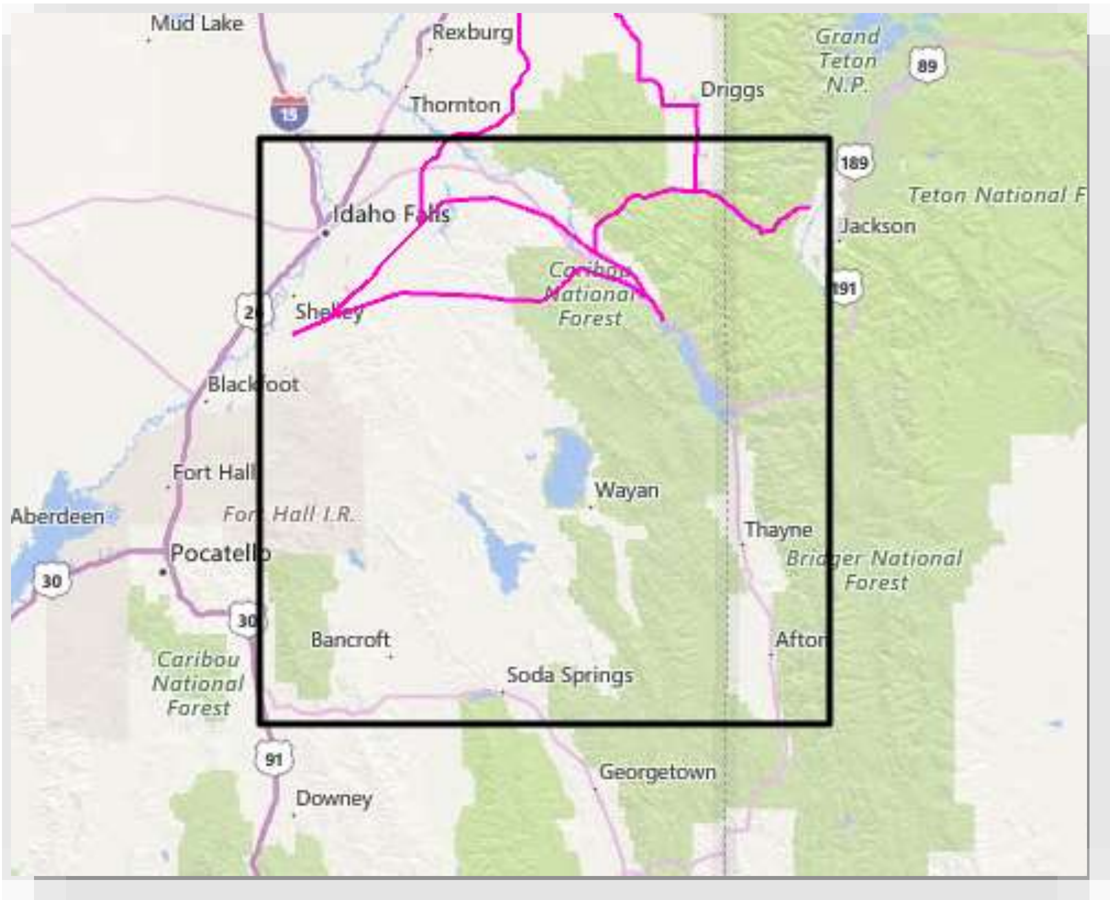
- Description: This project will accommodate the retirement of Conkelley substation. When the substation is retired, all substation facilities will be removed. The existing Libby-Conkelley, Hungry Horse-Conkelley, and Columbia Falls-Conkelley 230 kV lines will be tied together at Conkelley. Also, the existing Libby-Conkelley line will be looped into the Flathead 230 kV substation and a sectionalizing breaker will be added at Flathead. These changes will eliminate the existing Libby-Conkelley and Conkelley-Hungry Horse lines and create a new Libby-Flathead 230 kV line and a new 3 terminal Flathead-Columbia Falls-Hungry Horse 230 kV line.
- Purpose: This project is not required to meet TPL performance requirements.
- Estimated Costs: $27,600,000
- Expected Energization: 2024

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.15 Southeast Idaho/Northwest Wyoming Area

This load area includes southeast Idaho from Idaho Falls south to Soda Springs and east to Jackson, Wyoming. This area is served by Lower Valley Energy. It also includes the area from West Yellowstone, Montana south to Afton, Wyoming which is served by Fall River Electric Cooperative. This area includes the communities of Jackson, Wyoming and Driggs, Idaho.



The customers in this area include:

- Lower Valley Energy
- Fall River Electric Cooperative (FEC)
- U.S. Bureau of Reclamation (USBR)
- Utah Associated Municipal Power Systems (UAMPS)

The load area is served by the following major transmission paths or lines:

- Goshen-Drummond 161 kV line
- Goshen-Swan Valley 161 kV line
- Goshen-Palisades 115 kV line

Southeast Idaho/Northwest Wyoming Area

Local Generation and Load

Local generation serving the load area includes:

- USBR Palisades Dam (160 MW) (limited to about 8 MW in winter)
- Horse Butte Wind Project (60 MW in summer)

Southeast Idaho/Northwest Wyoming Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
146	292	153	309	161	333	1.0	1.5

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

The Southeast Idaho system is a winter peaking system. Load growth in the area is centered on Jackson, Wyoming and Driggs, Idaho. The load is mostly residential with growth in vacation homes. There is a smaller percentage of mining loads, mostly in the southern portion of the system. Loads tend to peak on holidays, especially Christmas and New Year's. The Fall River area has a great deal of spring and summer irrigation load. In order to keep area load growth flat any non-wires solution would need to reduce loads by 4.7 MW per year.

A number of non-wires solutions have already been employed in the Jackson, Wyoming area, including use of propane to heat much of the new construction. There are also snow-making machines near Jackson that can be shut down for peak shaving purposes if a critical contingency occurs. Previous non-wires analysis has suggested adding gas-fired peaking generation in the Jackson area.

Southeast Idaho/Northwest Wyoming Area

Proposed Plans of Service

Spar Canyon 230 kV Reactor Addition

- Description: This project adds a 230 kV 25 Mvar shunt reactor at Spar Canyon Substation.
- Purpose: This project improves the ability to maintain voltage schedules and increases operations and maintenance flexibility at Spar Canyon.
- Estimated Cost: $3,800,000
- Expected Energization: 2022

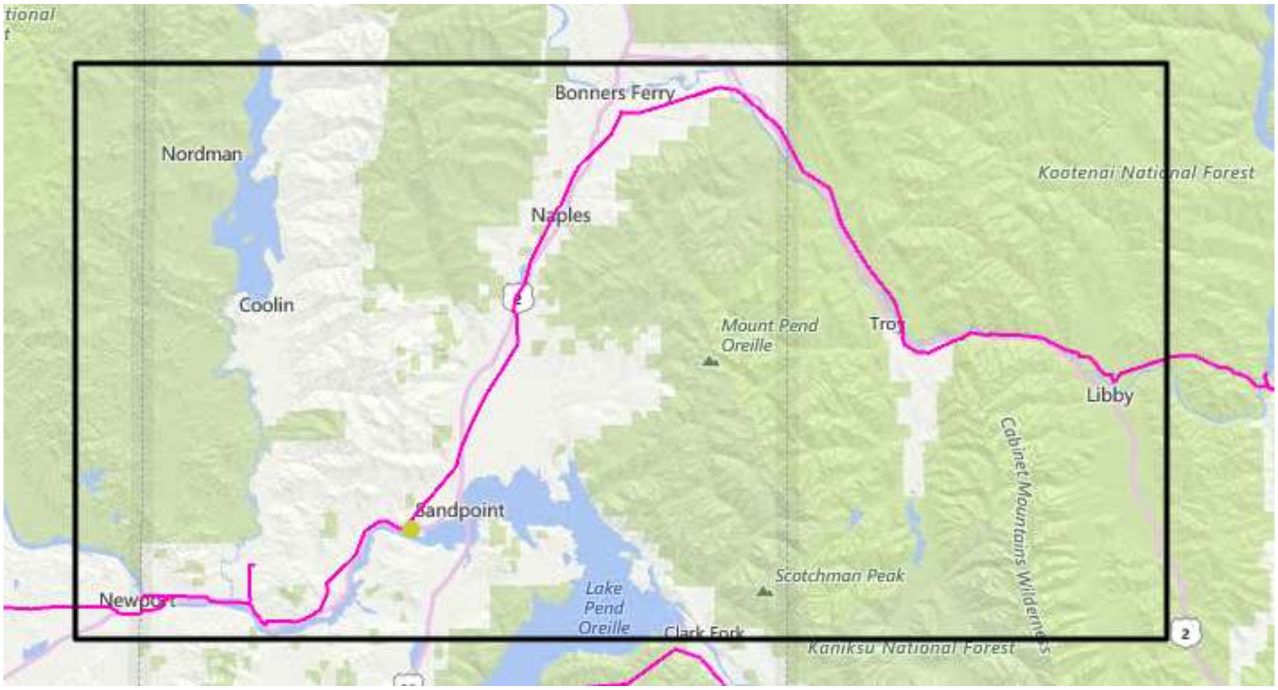
Recently Completed Plans of Service

Palisades-Snake River Transfer Trip Addition

- Description: BPA will work with the U.S. Bureau of Reclamation to install transfer trip on the Palisades-Snake River 115 kV line.
- Purpose: This project is needed to maintain reliability in the Southeast Idaho load area.
- Estimated Cost: $200,000
- Expected Energization: 2019

13.1.16 North Idaho Area

The North Idaho area encompasses northeast Bonner County and Boundary County in Idaho and western Lincoln County in Montana. The main communities are in the Sandpoint, Idaho vicinity. This area includes Newport, Washington and Priest River, Idaho to the west, Bonners Ferry and Moyie Springs to the north, Troy and Libby, Montana to the east, and the communities along the Clark Fork River in Idaho to the south.



The customers in this area include:

- Avista
- Northern Lights Electric Cooperative (NLI)
- City of Bonners Ferry (CBF)
- City of Troy
- Flathead Electric Cooperative (FEC)

The load area is served by the following major transmission paths or lines:

- Libby-Bonners Ferry 115 kV line 1
- Sand Creek-Bonners Ferry 115 kV lines 1 and 2 (currently operated as a single circuit)
- Albeni Falls-Sand Creek 115 kV line 1
- Avista Cabinet Gorge-Bronx-Sand Creek 115 kV line 1

North Idaho Area

Local Generation and Load

The local generation in the area includes

- USACE Libby (605MW)
- USACE Albeni Falls (48 MW)
- EWEB Smith Falls (36 MW)
- Avista Cabinet Gorge (287 MW)
- Avista Noxon (586 MW)
- NLI Lake Creek (3 MW)
- CBF Moyie (2 MW)

To a lesser extent the following hydroelectric generation can impact the North Idaho load area:

- USBR Hungry Horse (428 MW)
- Cogentrix Energy Lancaster (301 MW)
- Avista Boulder (25 MW)
- Seattle City Light Boundary (1040 MW)

North Idaho Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
101	188	122	191	123	199	0.2	0.8

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

The forecasted load growth in the area is less than one percent year. Flathead Electric Cooperative participated in the Pacific Northwest Smart Grid Demonstration Project, which was a five-year project that started in 2010. This project involved completing the deployment of FEC's automated meter-reading system (AMS). Additionally, FEC launched a pilot project called Peak Time, which was a voluntary demand response project. Avista also participated in the Pacific Northwest Smart Grid Demonstration Project and is continuing to install smart meters across its system. Lessons learned from these projects will help with future implementation of Smart Grid and demand response programs in the area. These programs could potentially result in shaving load during peak hours which could help defer the need date for the shunt capacitor addition at Libby FEC or Troy.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

North Idaho Area

Proposed Plans of Service

Libby FEC 115 kV Shunt Capacitor Replacement or Restoration

- Description: This project refurbishes the existing unusable 115 kV shunt capacitor at the Libby FEC Substation.
- Purpose: This project is required to maintain adequate voltages in the area following contingencies that involve loss of the connection to the Libby 230 kV system.
- Estimated Cost: $1,500,000
- Expected Energization: 2023

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.17 North Oregon Coast Area

The North Oregon Coast area includes Tillamook and Clatsop counties along the Oregon Coast. It is bounded by the Clatsop and Tillamook State Forests on the east and the Pacific Ocean on the west. It is bounded by the Columbia River to the north and Pacific City to the south. The population areas include Astoria, Seaside, Cannon Beach, Manzanita, Tillamook, Oceanside, Hebo, and Pacific City.

The customers in this area include:

- PacifiCorp
- Portland General Electric
- Tillamook Public Utility District
- West Oregon Electrical Coop
- Wahkiukum Public Utility District
- Clatskanie Public Utility District

The load area is served by the following major transmission paths or lines:

- Allston-Driscoll #2 115 kV line
- Clatsop 230/115 kV transformer
- Astoria-Driscoll #1 115 kV line
- Forest Grove-Tillamook #1 115 kV line
- Carlton-Tillamook #1 115 kV line
- Grand Ronde-Boyer #1 115 kV line

North Oregon Coast Area

Local Generation and Load

Local generation serving the load area includes:

- Clatskanie Public Utility District Wauna Generation at James River Mill (27 MW)

North Oregon Coast Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
141	270	187	291	197	304	1.0	0.9

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

The load makeup of the North Oregon Coast load area includes industrial, commercial, and residential loads. Industries on the North Oregon Coast include paper and wood mills. The North Oregon Coast load area meets the performance requirements for the near term and long term planning horizon. The North Oregon Coast transmission system will also meet the expected load growth for the ten-year planning horizon.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

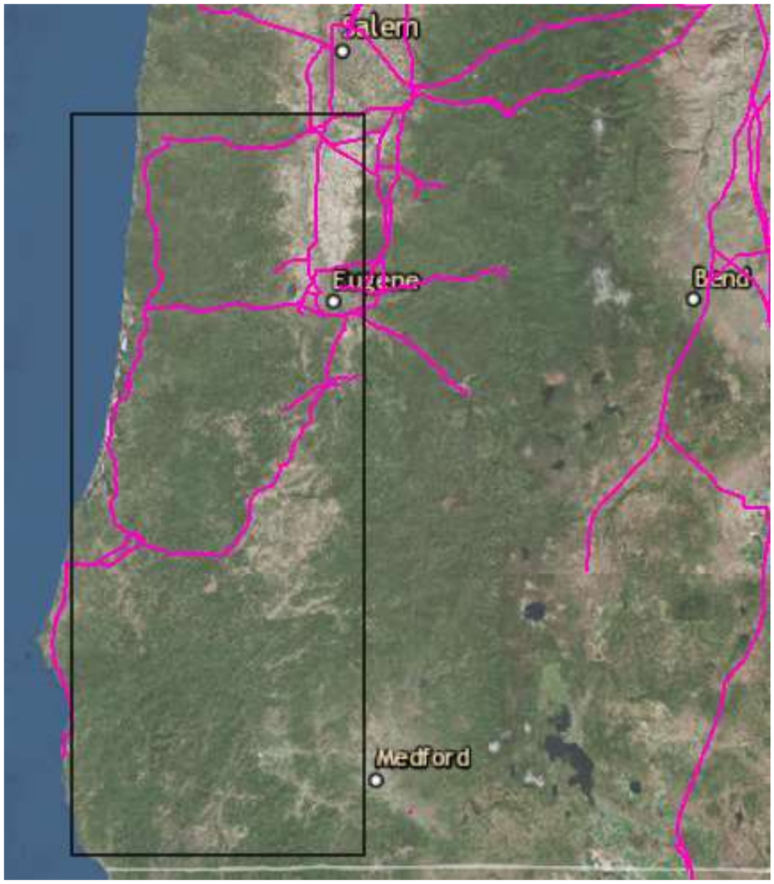
There are no proposed projects for this area at this time.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.18 South Oregon Coast Area

The South Oregon Coast load area includes the communities of Newport, Waldport, Florence, Reedsport, Coos Bay, Coquille, Bandon, Myrtle Point, Gold Beach, Port Orford, and south to Brookings. The load area is bounded by the north Oregon Coast to the north and the Salem-Albany and Eugene areas to the east and north.



The customers in this area include:

- PacifiCorp (PAC)
- Coos Curry Cooperative
- City of Bandon
- Douglas Electric Coop
- Central Lincoln Public Utility District

The load area is served by the following major transmission paths or lines:

- Lane-Wendson 230 kV line 2
- Alvey-Fairview 230 kV line 1
- Reston-Fairview 230 kV line 2
- Fairview-Rogue 230 kV line 1
- PAC Fairview-Isthmus 230 kV line 2
- Santiam-Toledo 230 kV line 1

South Oregon Coast Area

Local Generation and Load

There is no local generation in this area.

South Oregon Coast Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
259	505	268	476	272	534	0.3	2.3

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Proposed Plans of Service

Fairview 115 kV Reactor Additions

- Description: This project adds two 115 kV shunt reactors (approximately 25 Mvar each) at Fairview Substation.
- Purpose: This project is required to maintain acceptable voltage schedules in the South Oregon Coast area.
- Estimated Cost: $10,300,000
- Expected Energization: 2023

Central Oregon Cost O&M Flex Project Includes:

Toledo 69 kV and 230 kV Bus Tie Breaker Additions (Combined with the project below.)

- Description: This project adds a 69 kV bus tie breaker and a 230 kV bus tie breaker at Toledo Substation.
- Purpose: This project improves operations and maintenance flexibility at Toledo.
- Estimated Cost: $4,800,000
- Expected Energization: 2023

Wendson 115 kV Bus Tie Breaker Addition (Combined with the project above.)

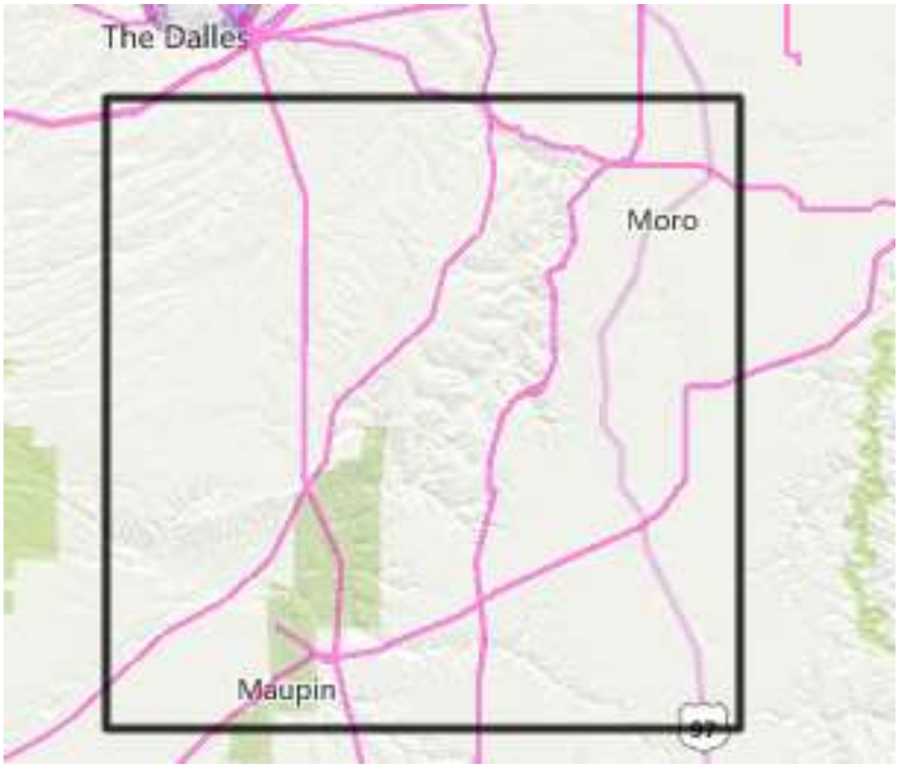
- Description: This project adds a 115 kV bus tie breaker at Wendson Substation.
- Purpose: This project improves operations and maintenance flexibility at Wendson.
- Estimated Cost: See above
- Expected Energization: 2023

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.19 DeMoss/Fossil Area

This DeMoss/Fossil load area spans a portion of north central Oregon, including the communities of Maupin, Tygh Valley, and Grass Valley. It encompasses Wasco and Sherman counties in Oregon.



The customers in this area include:

- Wasco Electric Cooperative (WEC)
- Columbia Basin Electric Cooperative
- Columbia Power Cooperative Association
- PacifiCorp

The DeMoss/Fossil load area is served by the following major transmission paths or lines:

- From the north by the Big Eddy-DeMoss 115 kV line
- From the west by the Big Eddy-Redmond 230 kV line (via WEC's Maupin-Fossil 69 kV line)

DeMoss/Fossil Area

Local Generation and Load

The local generation includes The Dalles Dam (2084 MW), Seawest's Condon Wind (50 MW) and PaTu Wind (10 MW).

DeMoss/Fossil Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
29	44	30	36	31	38	0.7	1.1

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

In order to keep peak load growth flat, a load reduction of approximately 0.3 MW per year would be required. This area is unusual in that it is constrained by an oversupply of generation, rather than load. Load growth in this area is actually beneficial to the transmission system. Loads in the area are a mix of residential and agricultural – a breakdown of load types is not available. There is no known demand response or smart grid projects in the area.

Proposed Plans of Service

There are no proposed projects for this area as this time.

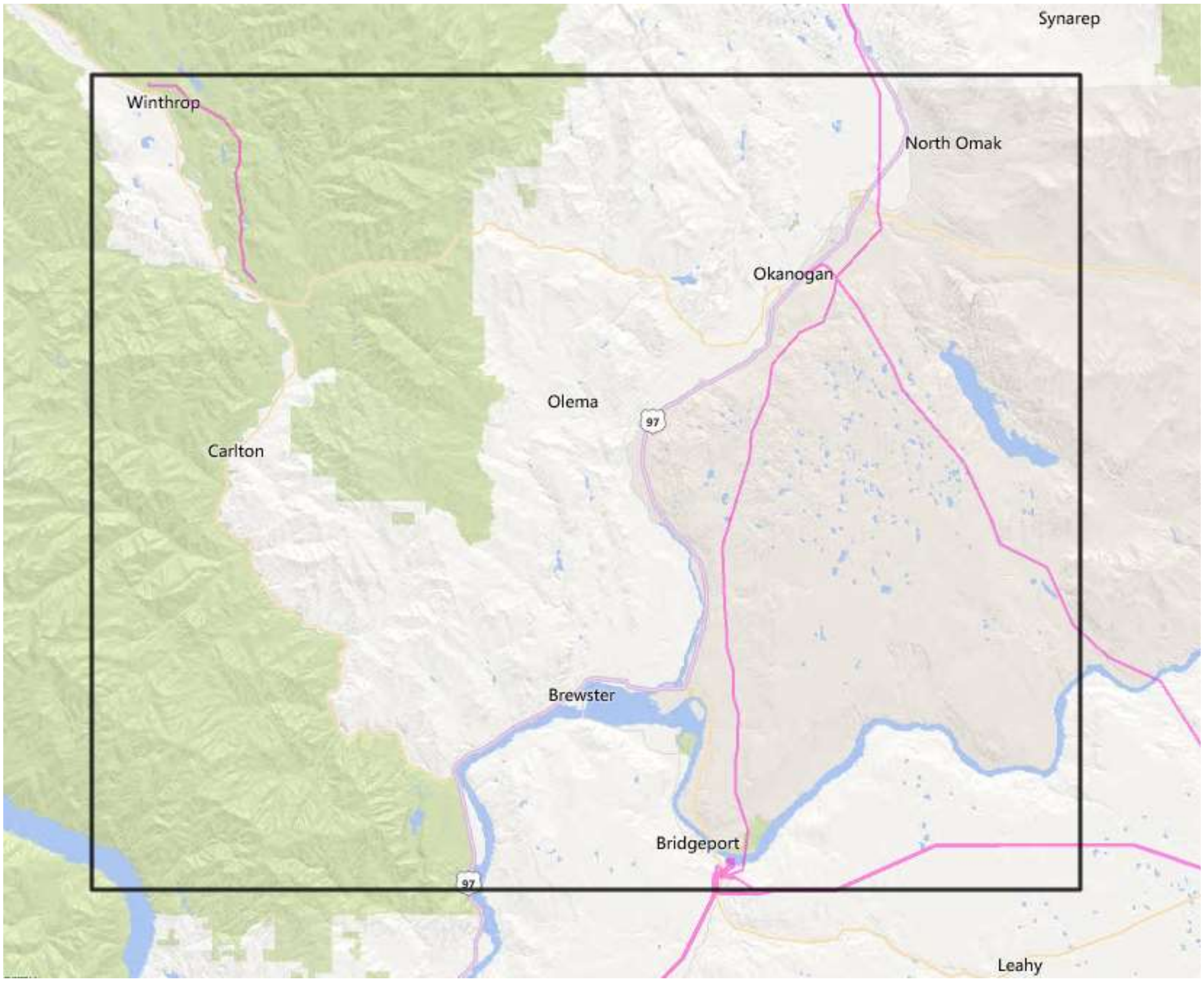
Recently Completed Plans of Service

DeMoss 69 kV Shunt Capacitor (3.5 Mvar) Addition

- Description: This project adds a 69 kV shunt capacitor (3.5 Mvar) at the DeMoss substation.
- Purpose: This project is required to maintain voltage schedules in the local area.
- Estimated Cost: $5,000,000
- Energization: 2019

13.1.20 Okanogan Area

This area includes the Okanogan Valley area of north central Washington including the communities of Omak, Brewster, Bridgeport, Winthrop, Twisp, Pateros, Tonasket, and Okanogan.



The customers in this area include:

- Okanogan Public Utility District
- Okanogan Cooperative
- Douglas Public Utility District (Douglas)
- Nespelem Valley Electric
- Ferry County Public Utility District

The load area is served by the following major transmission paths or lines:

- Chief Joseph-East Omak #1 230 kV line
- Grand Coulee-Okanogan #2 115 kV line
- Grand Coulee-Foster Creek #1 115 kV line
- Wells-Foster Creek 115 kV line (Douglas)

Okanogan Area

Local Generation and Load

Generation serving this load area includes:

- Chief Joseph Dam (2,614 MW)
- Grand Coulee Dam (7,079 MW)
- Wells Dam (851 MW)

Okanogan Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
158	232	201	270	213	302	1.2	2.3

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

Grand Coulee– Foster Creek (Nilles Corner) 115 kV Line Upgrade

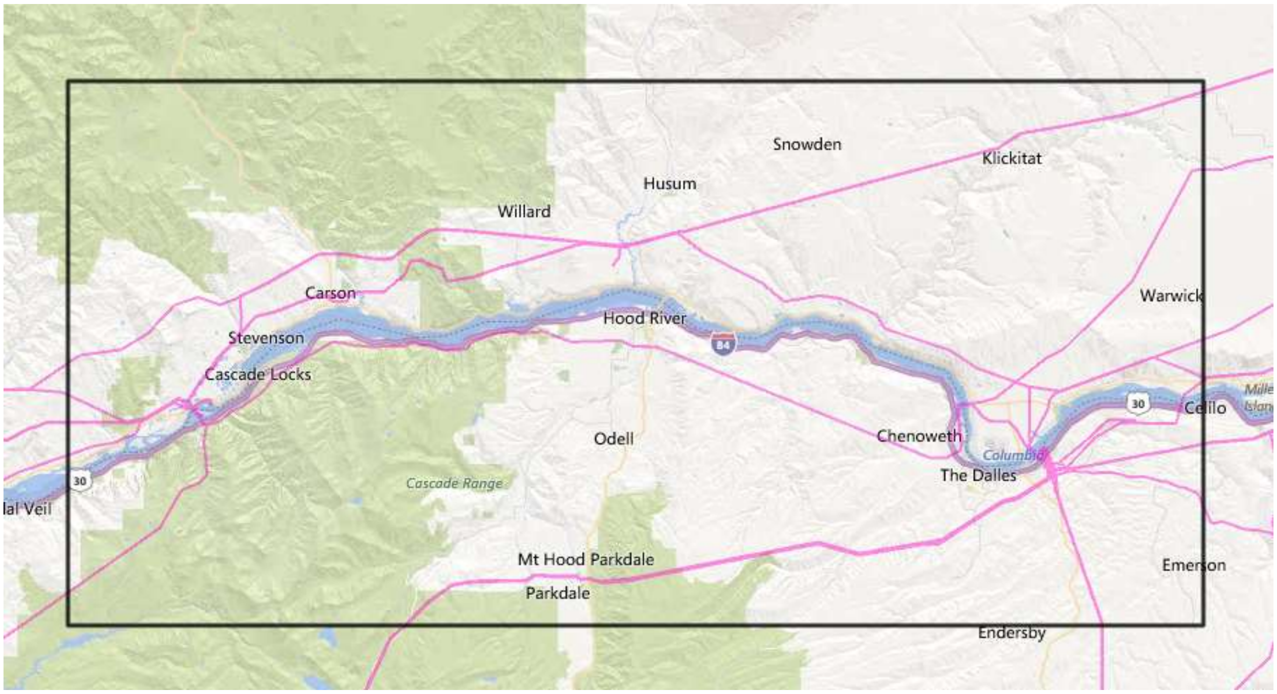
- Description: This project will remove impairments on the Grand Coulee-Nilles Corner section of the Grand Coulee-Foster Creek #1 115 kV line to facilitate increasing the maximum operating temperature of the line to 80 °C.
- Purpose: This project is required to maintain reliable load service to the Okanogan Load area during peak summer conditions.
- Estimated Cost: $650,000
- Expected Energization: 2021

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.21 Hood River/The Dalles Area

The Hood River/The Dalles area includes portions of northern Oregon and southern Washington along the Columbia River Gorge. The area spans from Bonneville Dam to the west, to The Dalles Dam to the east. It includes the communities of Cascade Locks, Hood River and The Dalles in Oregon and Stevenson, Carson, White Salmon and Bingen in Washington.



The customers in this area (and the communities they serve) include:

- Klickitat County Public Utility District in White Salmon and Bingen
- Skamania County Public Utility District in Stevenson and Carson
- City of Cascade Locks in Cascade Locks
- PacifiCorp in Hood River
- Hood River Electric Coop in Hood River
- Northern Wasco Public Utility District in The Dalles
- USBR in The Dalles

The load area is served by the following major transmission paths or lines:

- Bonneville Powerhouse 1 – Alcoa 115 kV line
- Bonneville Powerhouse 1 – North Camas 115 kV line
- Bonneville Powerhouse 1 – Hood River 115 kV line
- Chenoweth 230/115 kV transformer
- Big Eddy-Chenoweth 115 kV line
- Big Eddy-The Dalles 115 kV line

Hood River/The Dalles Area

Local Generation and Load

Generation serving this area includes:

- USACE Bonneville Powerhouse 1 and 2 (1225 MW)
- USACE The Dalles Powerhouse (2080 MW)
- SDS Lumber Generation (10 MW)
- Farmers Irrigation District Plant 2 (1.8 MW)

Hood River/The Dalles Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
221	274	373	422	457	507	4.1	3.7

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future. There are possibilities for non-wires efforts in the load area. Energy efficiency (EE) would be a useful tool in a particular area to offset constantly lowering voltages at a substation. EE measures could be catered to the large amount of residential load in the area, as well as any commercial or industrial load. There is also the possibility of demand management where peak load could be shifted to off-peak hours by commercial or residential customers. In order to mitigate load growth due to residential load, approximately three MW of load per year would have to be reduced by non-wires.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

There are no proposed projects for this area as this time.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

12.1.22 Pendleton/LaGrande Area

This area includes the eastern Oregon communities of Pendleton and La Grande. The Pendleton/La Grande load area is located in northeastern Oregon and extends east to the Idaho border and north to the Columbia River.

The customers in this area include:

- Oregon Trail Electric Cooperative
- PacifiCorp
- Umatilla Electric Cooperative
- Columbia Power Cooperative Association
- Columbia Basin Electric Cooperative

The load area is served by the following major transmission paths or lines:

- From the east by the LaGrande-(IPC) North Powder 230 kV line
- From the west by the McNary-Roundup 230 kV line

Pendleton/LaGrande Area

Local Generation and Load

There is no generation inside the Pendleton/La Grande cut-plane. Horizon Wind Energy's Elkhorn Wind Power Project is adjacent to BPA's Pendleton/La Grande study area.

The local generation in the area includes:

- Horizon's Elkhorn Valley Wind Project (110 MW)

Pendleton/LaGrande Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
146	139	151	143	150	142	-0.1	-0.1

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

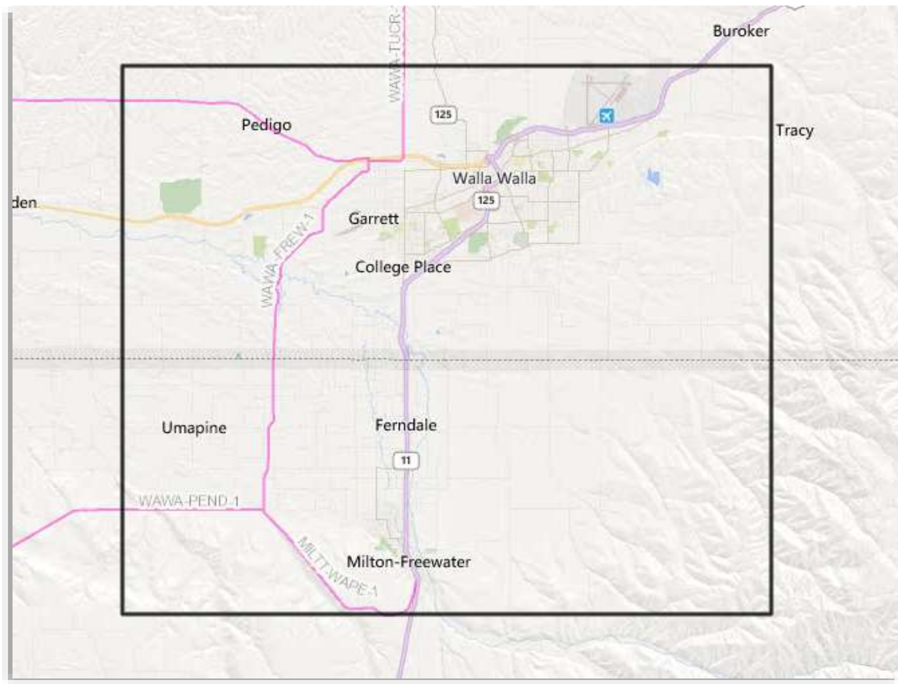
There are no proposed projects for this area at this time.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.23 Walla Walla Area

The Walla Walla load area is located in southeastern Washington and northeastern Oregon. This area includes the southeastern Washington city of Walla Walla and the southeastern Oregon community of Milton-Freewater to the south.



The customers in this area include:

- City of Milton-Freewater
- PacifiCorp (PAC)
- Clearwater Power Co.
- Columbia Rural Electric Association
- Inland Power and Light
- Umatilla Electric Cooperative

The load area is served by the following major transmission paths or lines:

- PAC Wanapum-Walla Walla 230 kV line
- PAC Wallula-Walla Walla 230 kV line
- IPC Walla Walla- Hurricane 230 kV line
- PAC Talbot-Walla Walla 230 kV line
- Franklin-Walla Walla 115 kV line
- Walla Walla-Tucannon River 115 kV line

The area has the following wind generating resources in the area:

- NextEra Energy Resources Stateline Wind (92 MW)
- Vansycle Ridge Wind (25 MW)
- Puget Sound Energy Hopkins Ridge Wind (157 MW)
- Infigen Combine Hills II Wind (63 MW)

Walla Walla Area

Local Generation and Load

The local generation in this area includes:

- NextEra Energy Resources Stateline Wind (92 MW)
- Vansycle Ridge Wind (25 MW)
- Puget Sound Energy Hopkins Ridge Wind (157 MW)
- Infigen Combine Hills II Wind (63 MW)

Walla Walla Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
91	66	153	133	164	145	1.4	1.7

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

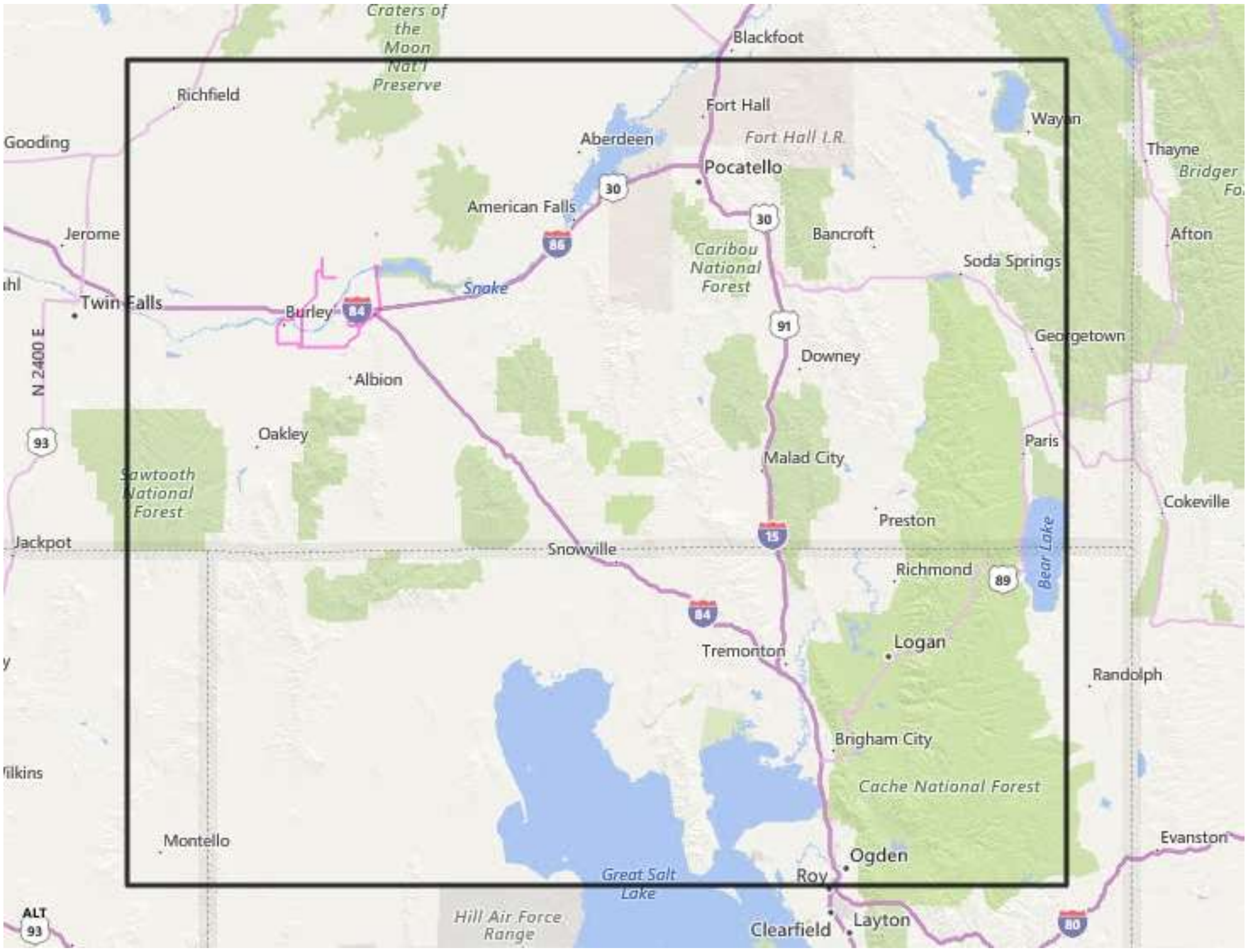
There are no proposed projects for this area at this time.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.1.24 Burley (Southern Idaho) Area

The Burley area is located in Minidoka and Cassia counties in south central Idaho. This area includes the communities of Burley, West Burley, Riverton, Minidoka, Rupert, and Heyburn. The area load is mostly residential and irrigation. Loads peak during the summer due to the irrigation load component.



The customers in this area include:

- Idaho Power
- Raft River Electric Coop
- Riverside Electric
- South Side Electric
- United Electric Coop
- Wells Rural Electric
- U.S. Bureau of Reclamation
- Burley Irrigation District
- East End Mutual
- Farmers Electric
- The Cities of Albion, Burley, Declo, Heyburn, Rupert, and Minidoka
- This load area is served primarily by Idaho Power transmission facilities.

Burley Area (Southern Idaho) Area

Local Generation and Load

Local generation in this load service area includes, Minidoka Power House (28 MW), Milner Power Plant (58 MW), and Bridge Geothermal (13 MW).

Burley Area Load							
Historical Peak Load (MW)		Five-Year Load 2023 (MW)		Ten-Year Load 2028 (MW)		Long-Term Annual Load Growth Rate (%)	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
192	154	193	134	197	136	0.4	0.3

Non-Wires Assessment

Transmission Planning along with the BPA agency team considers non-wires alternatives for reliability and transmission service needs. BPA defines non-wires solutions as the broad array of alternatives, including but not limited to, demand response, distributed generation, conservation measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system. If an area has a performance deficiency and a corrective action plan is identified within the near or long-term planning horizon, the potential for non-wires alternatives to correct deficiency or defer the date when a project is required to comply with the NERC Standards is considered. For an area with no recommended project the potential for a non-wires measure to slow or flatten the load growth in the area can defer the need for transmission reinforcements that may be identified in the future.

Presently, there are no transmission reinforcement projects proposed in this area within the ten-year planning horizon.

Proposed Plans of Service

There are no proposed projects for this area at this time.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

13.2.1 North of Hanford Path

Description

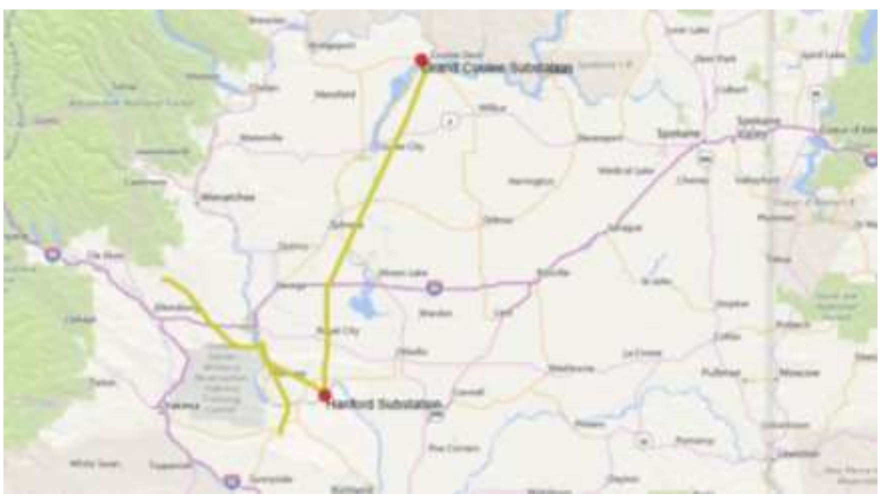
This path is located north of Hanford (NOH) substation between Hanford and Grand Coulee. The NOH path is located in central Washington and is a bi-directional path with a north-to-south and south-to-north flow.

The NOH path north to south peak flow occurs with high Upper Columbia generation, high Mid-Columbia generation, high I-5 Puget thermal generation, and/or high imports from Canada and lower levels on the Lower Snake River and Lower Columbia River hydro generation. High north to south flow is typical in the late spring and summer seasons. For thermal limitations the most critical season is summer, when facility ratings are lower.

The NOH south to north flows are dependent on a number of factors: low or zero generation on the Upper Columbia hydro, Grand Coulee pump loads in service, low Puget Sound area generation, and high south to north exports to Canada. The primary season for high south to north flows on NOH is the in spring and lesser often in the winter. The higher south to north flows is most common during light loads (off peak hours).

This path includes the following lines:

- Grand Coulee-Hanford 500 kV line 1
- Schultz-Wautoma 500 kV line 1
- Vantage-Hanford 500 kV line 1



Proposed Plans of Service

No projects are proposed for this path at this time.

The Schultz-Wautoma series capacitor project is on the North of Hanford path, but is for the South of Allston path. The project is not intended to reinforce the North of Hanford path, but is a significant change for the path.

Recently Completed Plans of Service

There are no projects that have been completed for this path since the previous planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

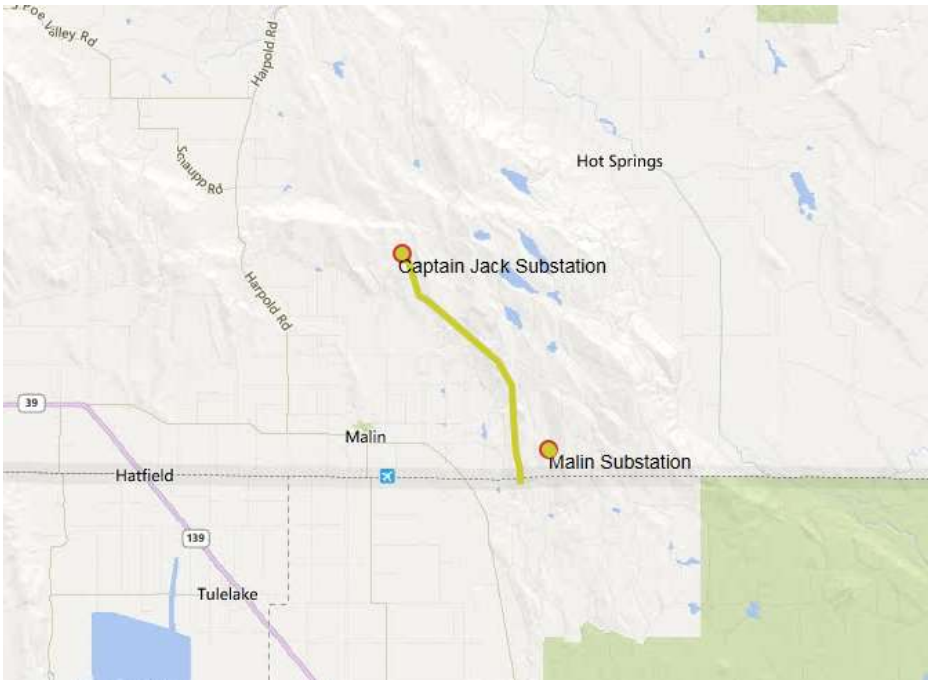
13.2.2 California-Oregon AC Intertie WECC Path 66 Includes North of John Day

Description

The California-Oregon intertie (COI), identified as Path 66 by WECC, is the alternating current (AC) Intertie between Oregon and California. It is a corridor of three roughly parallel 500 kV alternating current power lines connecting to the grids in Oregon and California. The combined power transmission capacity is about 4800 megawatts from north to south.

The path includes the following lines:

- Malin-Round Mountain 500 kV lines 1 and 2
- Captain Jack-Olinda 500 kV line



Proposed Plans of Service

No projects are proposed for this path at this time.

Recently Completed Plans of Service

Central Oregon Series Capacitor
(Slatt Series Capacitor Addition and Bakeoven Series Capacitor Upgrade)

- Description: This project involves adding a new 14 ohm series capacitor at Slatt Substation at the Slatt- Buckley 500 kV line and upgrading the existing series capacitors at Bakeoven in both John Day – Grizzly No. 1 and No. 2 500 kV lines by reducing the size from 25 ohms to 21.21ohms.
- Purpose: This project was initiated in response to line and load interconnection requests in the Central Oregon area which impacts the California-Oregon Intertie.
- Estimated Cost: $13,500,000
- Expected Energization: 2019

Potential Long-Range Needs

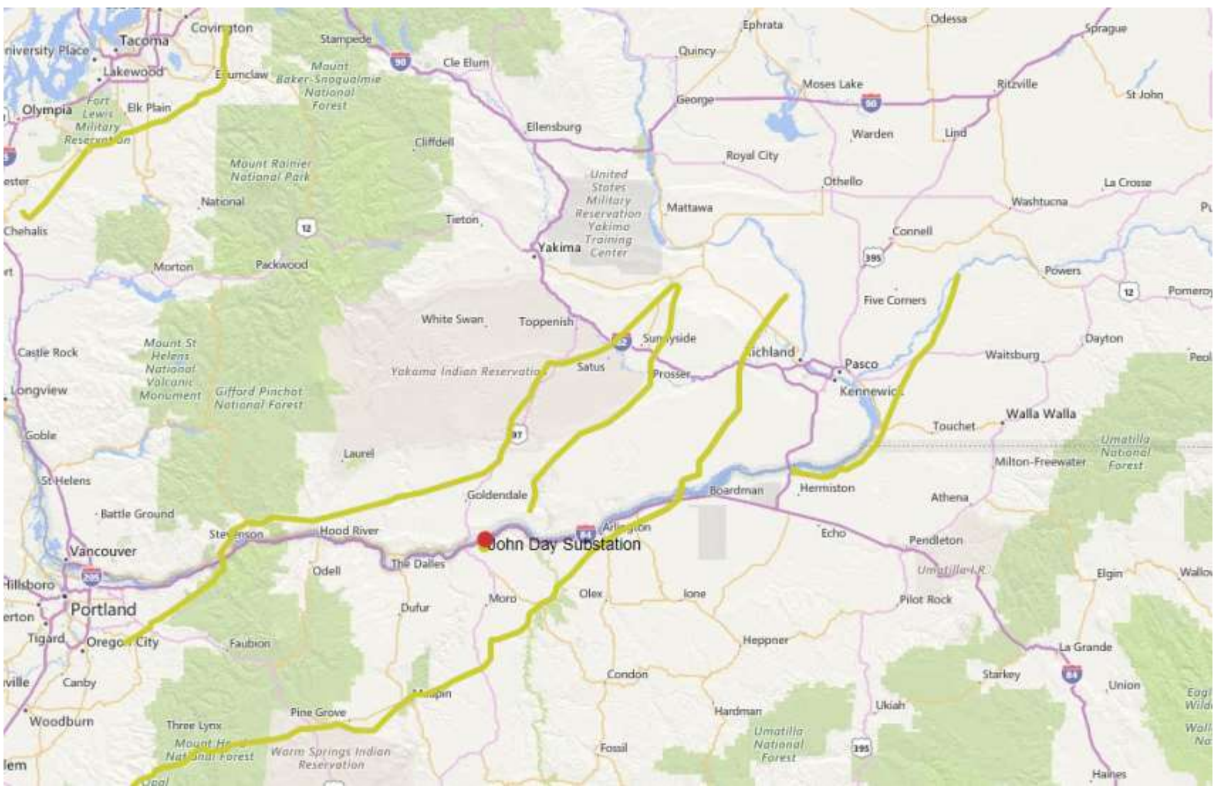
There are none identified for this path at this time.

North of John Day WECC Path 73 Description

The North of John Day (NJD) WECC Path 73 is located north of John Day Substation in Oregon. The path consist of six lines that run north to south through BPA's transmission system between the Upper and Lower Columbia river systems. The established rating of the NJD path is 8400 MW in the north to south direction. The limit for the NJD path is a measure used to ensure the voltage stability performance of the transmission system is adequate for high loading of the major Northwest to California paths simultaneously with high generation in the northern part of the system. The limit ensures the California Oregon Intertie (COI) is served via generation resources that are close to the COI path. The highest loading on the COI and NJD paths occurs during peak summer load conditions when the paths are simultaneously heavily loaded due to air condition usage in California and excess generation in the Northwest and Canada.

The path includes the following lines:

- Raver-Paul 500 kV No. 1
- Ashe-Marion 500 kV No. 2
- Wautoma-Ostrander 500 kV No. 1
- Ashe-Slatt 500 kV No. 2
- Wautoma-Rock Creek 500 kV No. 1
- Lower Monumental-McNary 500 kV No. 1



Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

13.2.3 Pacific DC Intertie WECC Path 65

PDCI Description

The Pacific DC Intertie, identified as Path 65 by WECC, is the direct current Intertie between Oregon and California and consists of a 500 kV high voltage direct current (HVDC) connection from BPA's Celilo Substation in Oregon to the Los Angeles Department of Water and Power's (LADWP) Sylmar Substation in California. This transmission line transmits electricity from the Pacific Northwest to the Los Angeles area using high-voltage direct current. The Intertie can transmit power in either direction, but power flows mostly from north to south. HVDC lines can help stabilize a power grid against cascading blackouts, since power flow through the line is controllable.

The path includes the following lines:

- 500 kV multi-terminal D.C. system between Celilo and Sylmar

Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no projects that have been completed for this path since the previous planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

13.2.4 West of Slatt / West of John Day / West of McNary Paths

West of Slatt Path Description

This path is located between Slatt and John Day Substations in Oregon. WOS is designed to protect the Lower Columbia Basin area from high transfers caused by surplus generation of local wind, hydro and thermal generation. WOJ is designed to protect for high transfers to Western Oregon load centers and to the northern terminal of the Pacific DC Intertie caused by surplus generation of local wind and hydro. Both paths due to surplus generation and are driven by commercial transfers instead of load service. WOS and WOJ can be impacted by West of McNary (WOM) path flows as well, since all three paths usually peak in spring or summer generation surplus conditions when commercial exports from the Pacific NW are high.

This path includes the following lines:

- Slatt-John Day 500 kV line 1
- Slatt-Buckley 500 kV line 1

Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

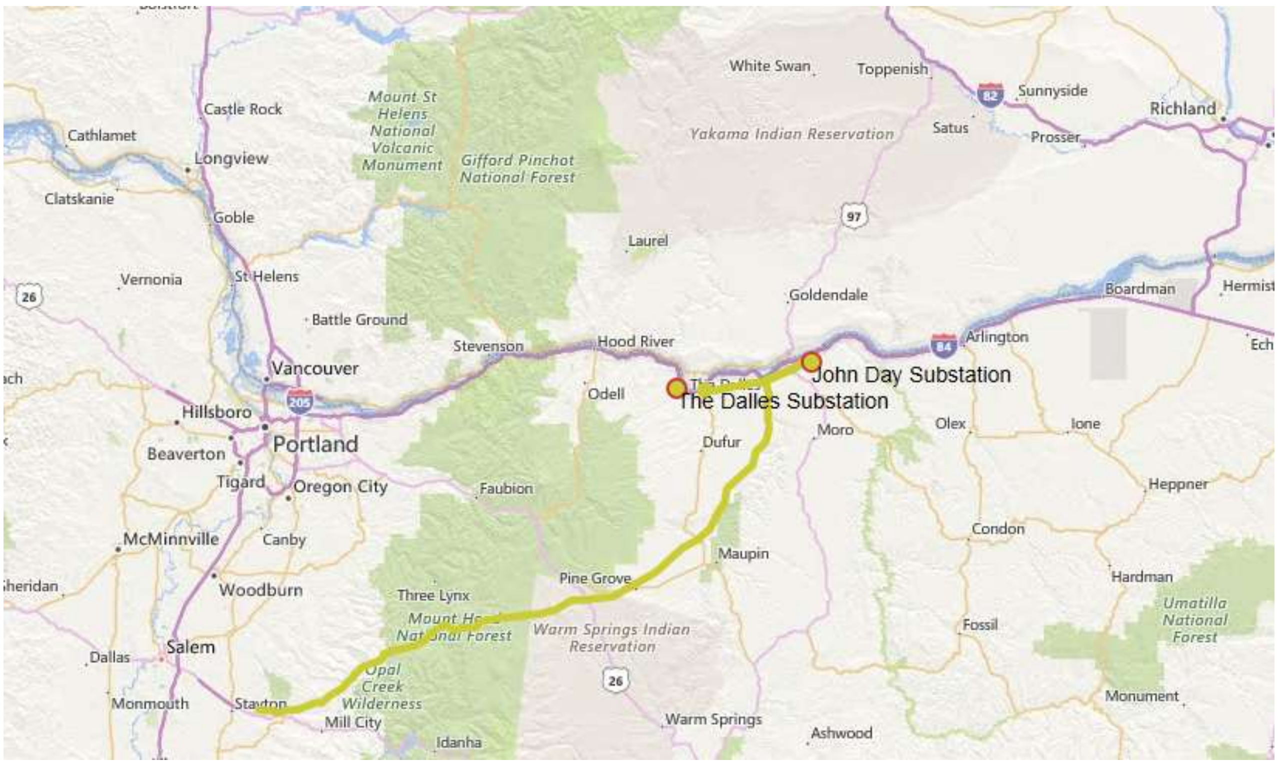
There are none identified for this path at this time.

West of John Day Description

This path is located between John Day Substation and The Dalles Substation in Oregon. WOS is designed to protect the Lower Columbia Basin area from high transfers caused by surplus generation of local wind, hydro and thermal generation. WOJ is designed to protect for high transfers to Western Oregon load centers and to the northern terminal of the Pacific DC Intertie caused by surplus generation of local wind and hydro. Both paths due to surplus generation and are driven by commercial transfers instead of load service. WOS and WOJ can be impacted by West of McNary (WOM) path flows as well, since all three paths usually peak in spring or summer generation surplus conditions when commercial exports from the Pacific NW are high.

This path includes the following lines:

- John Day-Big Eddy 500 kV line 1
- John Day-Big Eddy 500 kV line 2
- John Day-Marion 500 kV line 1



Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

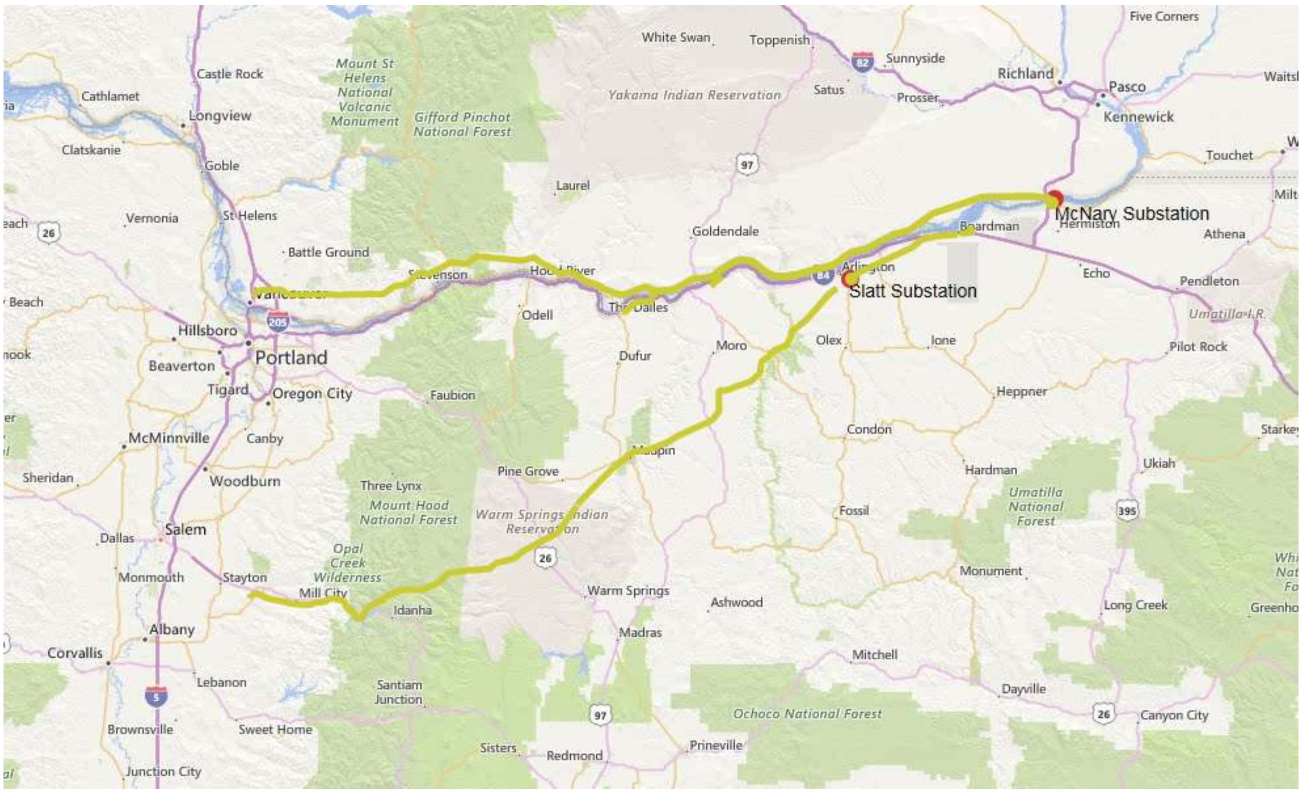
There are none identified for this path at this time.

West of McNary Path Description

This path is located between McNary and Slatt substations in Oregon. The West of McNary (WOM) is an east to west path that transfers power from Northeastern Oregon and Southeastern Washington, east of the city Arlington, to the California-Oregon Intertie (COI) at John Day substation, the Pacific DC Intertie (PDCI) at Big Eddy substation and Northwest (NW) load centers west of the Cascade Mountains. The WOM path is spring/summer peaking as a result of late spring and early summer run off. WOM path flow peaks when the following plants have high outputs: McNary and. Lower Snake River hydro; thermal plants at Coyote Springs, Calpine, Hermiston and Goldendale; and wind plants at Jones Canyon, Walla Walla and Central Ferry.

This path includes the following lines:

- Coyote Springs-Slatt 500 kV line 1
- McNary-John Day 500 kV line 2
- McNary-Ross 345 kV line 1
- Jones Canyon-Santiam 230 kV line 1
- Harvalum-Big Eddy 230 kV line 1



Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

13.2.5 Raver to Paul Path

Description

The Raver-Paul (RP) path is located east of Tacoma, WA and spans from near Covington, WA to Centralia, WA. The critical facilities in the area are the Raver, Paul, Covington, Tacoma, Olympia, and Satsop substations. This path is located between Raver and Paul Substations in western Washington. The generation projects in this area are the Centralia, Fredrickson LLP, Fredrickson PSE, Grays Harbor, and Chehalis thermal generation projects. In addition, the Fredonia and Whitehorn generation projects impact the area. The load in this area is a mixture of industrial, commercial, and residential loads in Covington WA, Tacoma WA, Olympia WA, and the Olympic Peninsula.

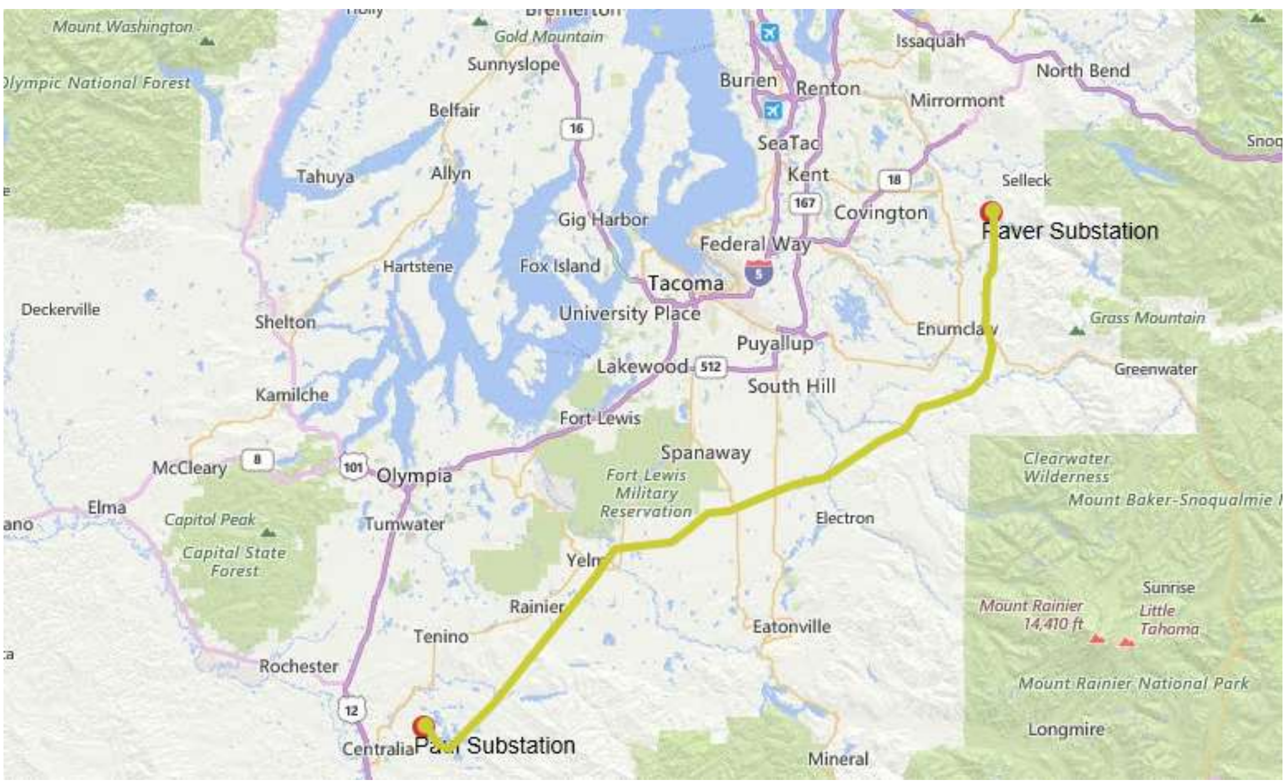
During late spring and early summer conditions, large amounts of hydro generation on-line in the Northwest and Canada, with moderate loads in the Northwest can occur simultaneously with I-5 Corridor thermal generation off-line due to maintenance schedules and economic factors.

This path includes the following line:

- Raver-Paul 500 kV Line 1

The customers in the area include:

- Puget Sound Energy (PSE)
- Tacoma Power
- Mason County #1 & #3 PUDs
- Jefferson County PUD
- Clallam County PUD
- City of Port Angeles
- Grays Harbor PUD



Proposed Plans of Service

St. Clair – South Tacoma 230 kV Line Upgrade

- Description: When the St. Clair 230 kV substation was energized in the summer of 2014, the South Tacoma-Olympia 230 kV line was resurveyed and four spans where de-rated from100 C MOT to 80 C MOT. This project will resag the four limiting spans of the South Tacoma – St. Clair 230 kV line from 80 deg. C MOT to 100 deg. C MOT.
- Purpose: this project is required to accomodate firm transmission service obligations once Centralia unit 1 retires.
- Estimated Cost: $400,000
- Expected Energization: 2020

Raver 500/230 kV Transformer (PSANI), (Also included in the Seattle, Tacoma and Olympia area.)

- Description: This project adds a 1300 MVA, 500/230 kV transformer at Raver Substation. This project is part of the overall Puget Sound Area/Northern Intertie (PSANI) Regional Reinforcement Plan. This is a joint project between participating utilities in the Puget Sound area.
- Purpose: This project is required to support load growth in the Puget Sound area.
- Estimated Cost: $60,000,000
- Expected Energization: 2020
  This project originally had an expected energization date of 2016, but energization has been delayed due to land acquisition issues. The project is currently in the execution phase.

Recently Completed Plans of Service

There are no projects that have been completed in this area since the previous planning cycle.

Potential Long-Range Needs

Centralia Unit No. 2 Re-termination

- The Centralia Unit No. 1 is planned to retire in 2020. Re-terminating BPA Unit No. 2 into its bay will eliminate a limiting breaker failure for the path. It is not required to meet the NERC Reliability Planning Standard, but it will increase operational flexibility.

13.2.6 Paul to Allston and South of Allston Paths

Paul to Allston Path Description

The Paul-Allston (P-A) path is located along the I-5 Corridor west of the Cascade Mountains and spans from near Alston Oregon to Sherwood Oregon. The main grid facilities located in this area are the Allston, Keeler, and Pearl substations. The Southwest Washington and Northwest Oregon load service area includes the cities of Portland, Oregon and Vancouver, Washington, which include high concentrations of industrial, commercial, and residential load. The P-A path is bi-directional (north-to-south and south-to-north).

This path includes the following lines:

- Napavine-Allston 500 kV line
- Paul-Allston 500 kV line

Proposed Plans of Service

Holcomb-Naselle 115 kV Line Upgrade (Also included in Southwest Washington Area.)

- This project will rebuild several spans to increase the line rating. The need date for this project is 2017. However, the expected energization date has been delayed due to wildlife mitigation requirements. The interim bridge measure currently in place is two special over current relays that will open either the Holcomb or Naselle end of the line based on the continuous rating of the line and which line section overloads first. The interim measure is sufficient for all conditions, but will result in non-consequential loss of local load for some contingencies as allowed by the Transmission Planning Standards.
- Purpose: This project is required to maintain reliable load service to the Southwest Washington Coast area.
- Estimated Cost: $10,400,000
- Expected Energization: 2021

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

South of Allston WECC path 71 Description

The South of Allston (SOA) path is located along the I-5 Corridor west of the Cascade Mountains and spans from near Alston Oregon to Sherwood Oregon. The main grid facilities located in this area are the Allston, Keeler, and Pearl substations. The Southwest Washington and Northwest Oregon load service area includes the cities of Portland, Oregon and Vancouver, Washington, which include high concentrations of industrial, commercial, and residential load.

This path includes the following lines:

- Keeler – Allston 500-kV
- Trojan – St. Marys 230-kV (PGE)
- Trojan – Rivergate 230-kV (PGE)
- Ross – Lexington 230-kV (rev)
- St. Helens – Allston 115-kV
- Merwin – St. Johns 115-kV (PACW)
- Seaside – Astoria 115-kV (PACW)
- Clatsop 230/115 kV (rev)

The highest flow across the SOA path occurs during peak summer load conditions combined with high north-to-south transfers from Canada through the Northwest to the Puget Sound, Portland, and California load areas. The high north to south flows occur due to excess generation in Canada and the Northwest and high energy demands in the Northwest and California.

Proposed Plans of Service

Schultz-Wautoma 500 kV Line Series Capacitors

- Description: This project is necessary to increase South of Allston (SOA) available transfer capability. The project will add 1152 Mvar, 24 OHM series capacitor (rated 4000A at 500 kV) on the Schultz-Wautoma line at the Wautoma substation.
- Purpose: This project will improve operations and maintenance flexibility for SOA and I-5 paths in the Tri-Cities area.
- Estimated Cost: $22,300,000
- Expected Energization: 2022

Longview 230/115 kV Transformer Addition (Also included in Longview Load Area.)

- Description: This project adds a 230/115 kV transformer in the Longview area. It may be possible to accomplish this by re-strapping an existing 230/69 kV transformer bank to 230/115 kV operation. In addition, this project adds a 230 kV bus sectionalizing breaker at the Longview substation, which will divide the south bus into two sections.
- Purpose: This project is required to maintain reliable load service to the Longview area. The breaker addition will resolve the issues caused by a 230 breaker failure outage at Longview.
- Estimated Cost: $15,000,000
- Expected Energization: 2022

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the previous planning cycle.

Potential Long-Range Needs

Keeler 500 kV Reconfiguration & Breaker Additions

- This BPA project will reconfigure the existing Keeler 500 kV ring bus into a breaker-and-a-half configuration by adding several new 500 kV breakers and re-terminating existing lines.
- Expected energization is beyond 2024.

Keeler-Rivergate 230 kV Line Upgrade

- This BPA project will increase the rating of the line. This project was identified as a beneficial upgrade to increase Operational and Maintenance flexibility for deeper contingency or extreme events.
- Expected energization is beyond 2024.

Keeler 500/230 kV No. 2 Transformer Addition

- This BPA project will add another 500/230 transformer bank at Keeler Substation, and will utilize one of the new bay positions created by the Keeler 500 kV Reconfiguration project.
- Expected energization is beyond 2028.

13.2.7 West of Cascades South WECC Path 5

The West of Cascades South path spans the Cascade Mountains in southern Washington and Northern Oregon, serving the Willamette Valley and Southwest Washington (WILSWA). The main grid facilities for this path include Marion, Ostrander, Knight, John Day, Wautoma, and Big Eddy substations. The Willamette Valley, Northwest Oregon, and Southwest Washington load service areas (WILSWA area) includes the cities of Portland, Vancouver, Eugene and Salem with high concentrations of commercial and residential load. The WOCS path only flows in the east-to-west direction.

This path includes the following lines:

- Big Eddy-Ostrander 500-kV (BPA)
- Knight-Ostrander 500 kV (BPA)
- Ashe-Marion 500 kV (BPA)
- Buckley-Marion 500 kV (BPA)
- John Day-Marion 500 kV (BPA)
- McNary-Ross 345 kV (BPA)
- Jones Canyon-Santiam 230 kV (BPA)
- Big Eddy-Chemawa 230 kV (BPA)
- Big Eddy-McLoughlin 230 kV (BPA)
- Big Eddy-Troutdale 230 kV (BPA)
- Midway-N. Bonneville 230 kV (BPA)
- Round Butte-Bethel 230 kV (PGE)

The highest flows across WOCS occurs during peak summer and winter load conditions in the WILSWA area combined with high generation east of the Cascade Mountains including hydro, wind, and thermal plants.

Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

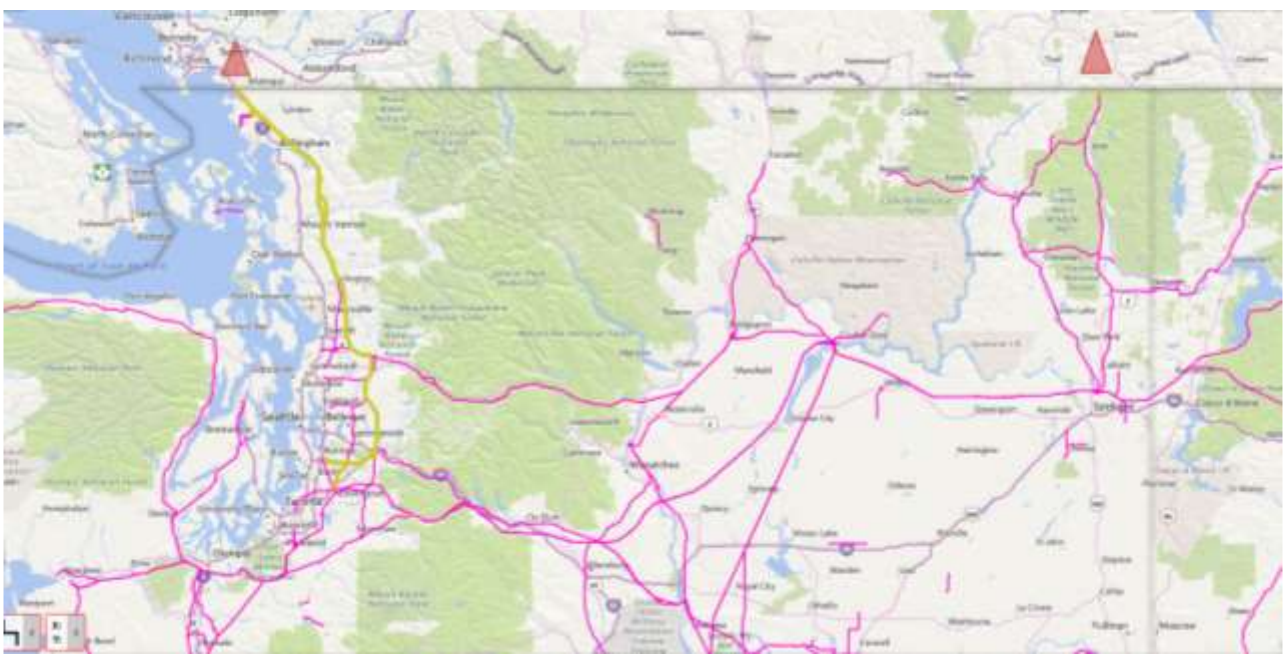
Pearl-Sherwood 230 kV Corridor Reconfiguration

- Split the existing BPA/PGE Pearl-Sherwood No.1 and 2 230 kV jumpered circuits and terminate them into separate bays at Pearl and Sherwood.
- Split the existing BPA/PGE Pearl-Sherwood-Mcloughlin 230 kV 3-terminal line into a new Pearl-Sherwood No. 3 230 kV line and a new Pearl-Sherwood-Mcloughlin 3 terminal line.
- This will be a joint project with PGE.
- Eliminates P1 outage (re-categorized as P7)
- Alleviate PGE Sherwood 230 kV line overloads during K-P south-to-north stress conditions.
- Expected energization is beyond 2027.

13.2.8 Northern Intertie / North of Echo Lake Path / South of Custer Path

All three paths are influenced by northwest Washington load areas, specifically the total loads and generation dispatches within the Puget Sound load areas (Seattle/Tacoma, Olympic Peninsula, and SW Washington Coast/Aberdeen). South-to-north conditions are most critical in the winter when local loads are the highest and exports to Canada are high; north-to-south conditions are most critical in the spring and summer when thermal facility ratings are at their lowest, imports from Canada are high, and local PSA generation is high.

Major customers in the Puget Sound include Puget Sound Energy (PSE), Seattle City Light (SCL), Snohomish PUD (SNPD), and Tacoma Power (TPU). Congestion in the PSA has been an issue for decades, thus several Puget Sound Area/Northern Intertie (PSANI) reinforcements were developed jointly between Seattle City Light, Puget Sound Energy and BPA in 2011 as a result of the Columbia Grid Puget Sound Area Study Team (PSAST).



Northern Intertie – Northwest to British Columbia WECC Path 3

The Northwest to British Columbia WECC Path 3, also known as the Northern Intertie, is between the United States and Canada. Bonneville delivers power to Canada over the Northern Intertie, which includes lines and substations from Puget Sound north to the Canadian border. It has a western and an eastern component and is bi-directional path that is dictated by import and export schedules from Canada. Several Puget Sound Area/Northern Intertie (PSANI) reinforcements were developed jointly between Seattle City Light, Puget Sound Energy and BPA in 2011 as a result of the Columbia Grid Puget Sound Area Study Team (PSAST). The Northern Intertie (NI) on the west side is a bi-directional path and flows are driven by import and export schedules from Canada.

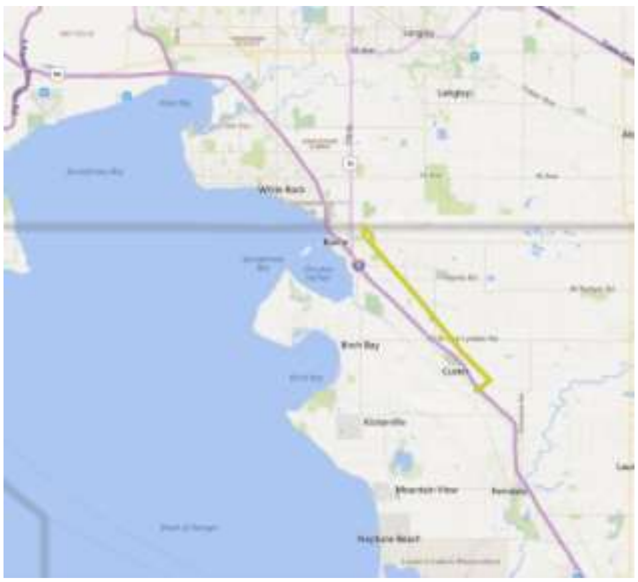
This path includes the following lines:

Western Component:

- Custer (BPA)-Ingledow (BCTC) 500 kV No. 1
- Custer (BPA)-Ingledow (BCTC) 500 kV No. 2

Eastern Component:

- Boundary (BPA)-Waneta (TECK) 230 kV
- Boundary (BPA)-Nelway (BCTC) 230 kV



Proposed Plans of Service

Raver 500/230 kV Transformer (PSANI), (Also included in the Seattle area.)

- Description: This project adds a 1300 MVA, 500/230 kV transformer at Raver Substation. This project is part of the overall Puget Sound Area/Northern Intertie (PSANI) Regional Reinforcement Plan. This is a joint project between participating utilities in the Puget Sound area.
- Purpose: This project is required to support load growth in the Puget Sound area.
- Estimated Cost: $72,000,000
- Expected Energization: 2020

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

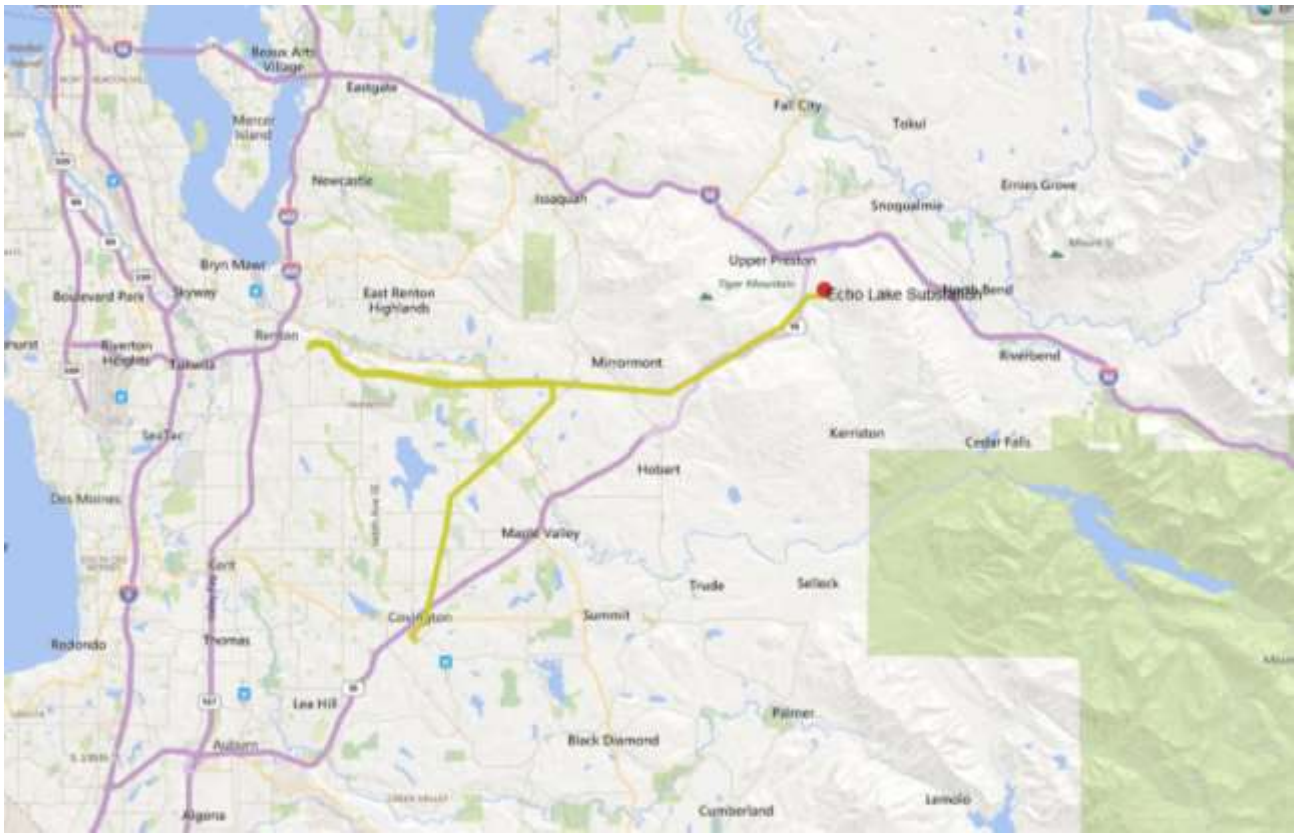
North of Echo Lake Path Description

North of Echo Lake (NOEL) path is a south-to-north path that connects the central Puget Sound Area (PSA). This path includes the following lines:

This path is located north of Echo Lake Substation in the Puget Sound area of Washington.

This path includes the following lines:

- Echo Lake-Maple Valley 500 kV lines 1 and 2
- Echo Lake-Snoking-Monroe 500 kV line
- Covington-Maple Valley 230 kV line 2



Proposed Plans of Service

Monroe 500 kV Line Re-terminations

- Description: This project reconfigures Monroe Substation by developing a new 500 kV bay and re-terminating the Custer and Chief Joseph 500 kV lines.
- Purpose: This project will increase reliability and capacity on the Northern Intertie.
- Estimated Cost: $10,2,000
- Expected Energization: 2020

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

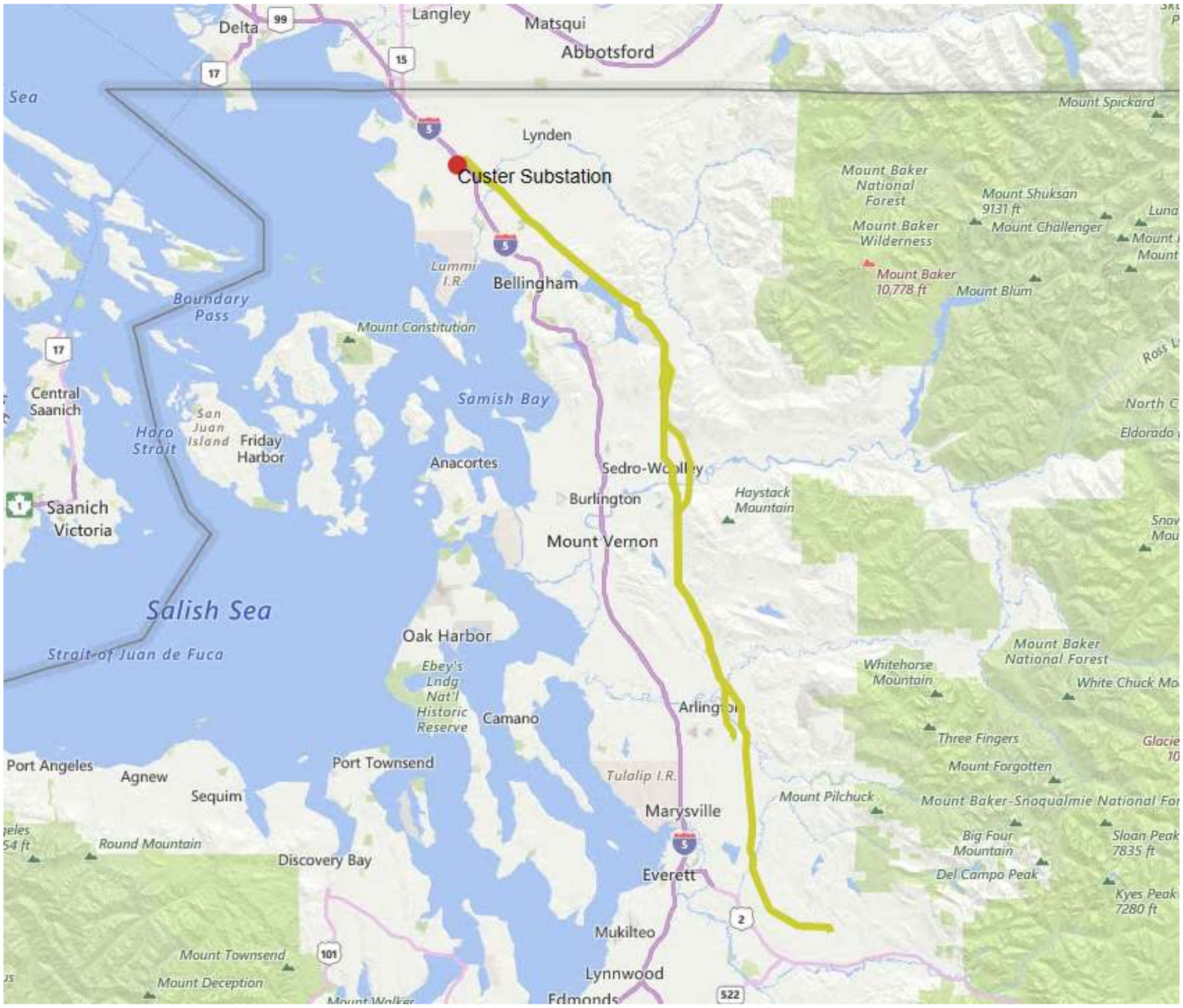
There are none identified for this path at this time.

South of Custer Path Description

South of Custer (SOC) is a north-to-south path that connects the northern PSA. This path is located south of Custer Substation in the Bellingham area of Washington State.

This path includes the following lines:

- Monroe-Custer 500 kV lines 1 and 2
- Custer-Bellingham 230 kV line 1
- Custer-Murray 230 kV line 1



Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

13.2.9 West of Cascades North WECC Path 4

Description

The West of Cascades North (WOCN) Path spans the northern Cascades Mountain range in Washington State. It connects generation hubs on the Columbia River in eastern Washington to load centers in Puget Sound and western Washington. It is comprised of system elements owned by BPA and PSE, and only flows in the east-to-west direction.

This path consists of the following transmission lines:

- Chief Joseph-Monroe 500 kV line (BPA)
- Schultz-Raver #1, #3, and #4 500 kV lines (BPA)
- Schultz-Echo Lake 500 kV line (BPA)
- Chief Joseph-Snohomish #3 and #4 345 kV lines (BPA)
- Rocky Reach-Maple Valley 345 kV line (BPA)
- Grand Coulee-Olympia 287 kV line (BPA)
- Rocky Reach-Cascade 230 kV line (PSE)
- Bettas Road-Covington 230 kV line (BPA)

Proposed Plans of Service

Schultz – Wautoma 500 kV Line Series Capacitor

- Description: A new 1152 Mvar, 24 Ohm series capacitor rate 4000 amps at 500 kV, installed at Wautoma substation on the Schultz – Wautoma 500 kV transmission line.
- Estimated Cost: $22,600,000
- Expected energization is 2021

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

Schultz-Raver 3 and 4 Reconductor and Series Capacitors

- The Schultz-Raver #3 line consists of 77 miles of ACSR 2.5" expanded conductor, and Schultz-Raver #4 kV line consists of 26 miles of ACSR 2.5" expanded conductor which is now obsolete since replacement parts are no longer available for the compression fittings for this type of conductor. This project is not required at this time to meet NERC TPL-001-04 performance requirements.
- Expected energization is beyond 2028.

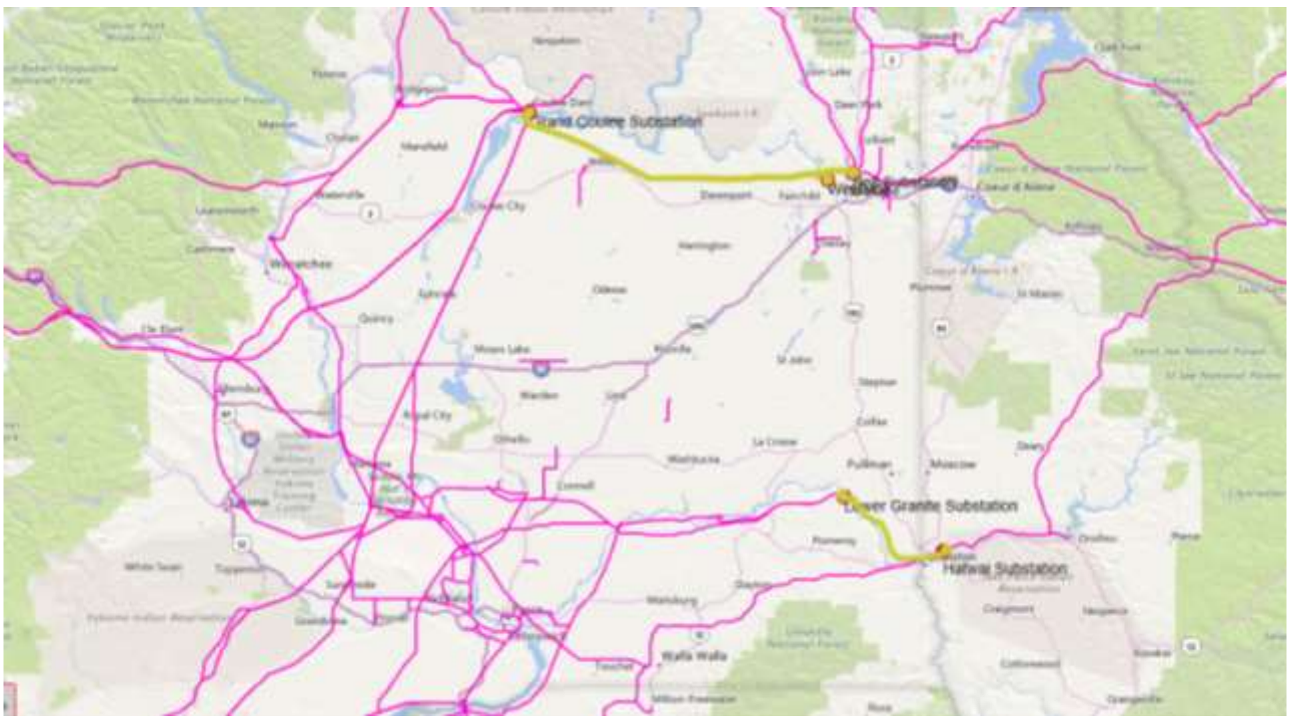
13.2.10 West of Hatwai Path / Montana to Northwest WECC Path 8 / West of Lower Monumental Path

West of Hatwai WECC Path 6 Description

This path is located between northern Idaho (Lewiston area) and eastern Washington. The highest flows on this path typically occur east to west during light load periods in late spring and early summer.

This path includes the following lines:

- BPA Lower Granite – BPA Hatwai 500 kV line
- BPA Grand Coulee – BPA Bell 230 kV lines 3 and 5
- BPA Grand Coulee – BPA Bell 500kV
- BPA Grand Coulee – BPA Westside 230 kV line
- BPA Creston – BPA Bell 115 kV line
- PacifiCorp Dry Creek – Talbot 230 kV line
- Avista North Lewiston – Tucannon River 115 kV line
- Avista Harrington – Odessa 115 kV line
- Avista Lind – Avista Roxboro 115 kV line
- PacifiCorp Dry Gulch 115/69 kV line



Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

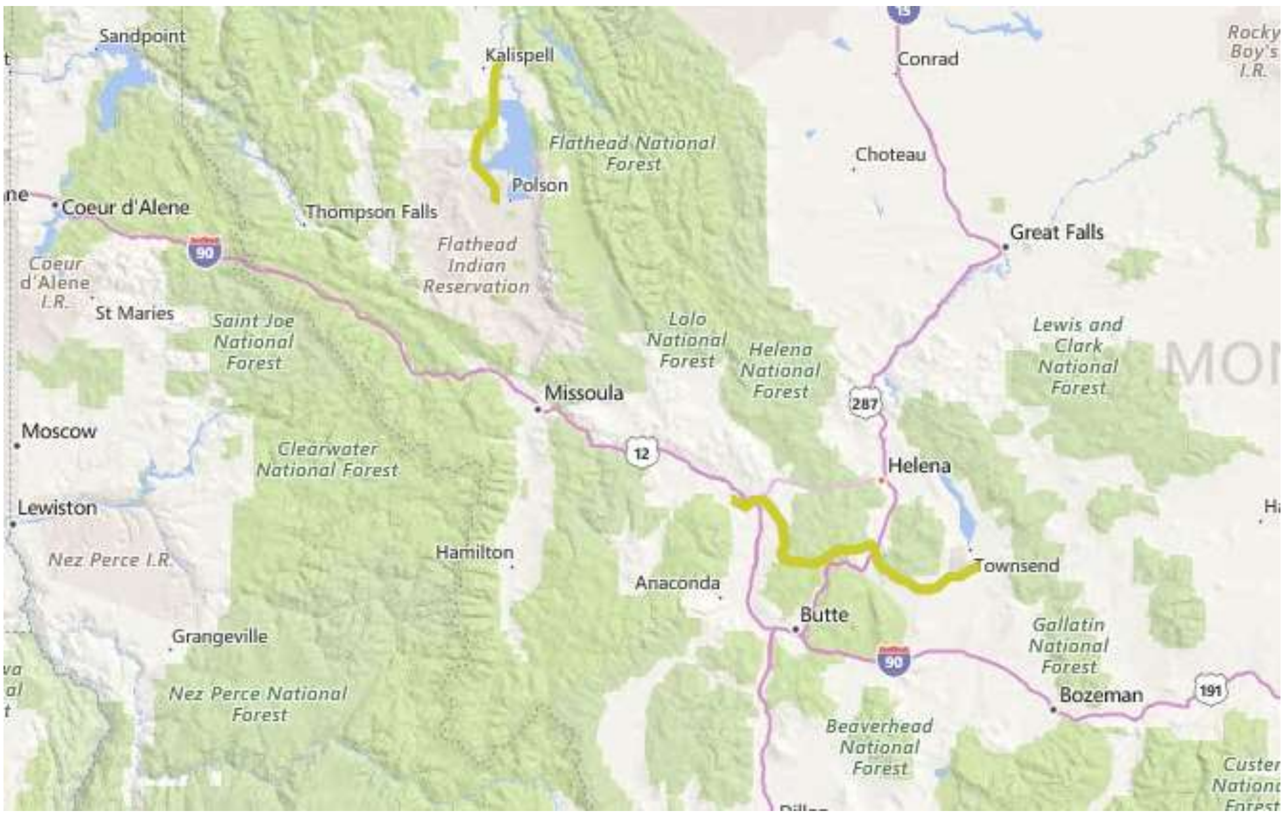
There are none identified for this path at this time.

Montana to Northwest WECC Path 8 Description

This path is the intertie between Montana and the Northwest. It includes Northwestern Energy, Avista and BPA lines. The highest flows on this path typically occur east to west during light load periods from mid-summer to early spring.

This path includes the following lines:

- BPA Kerr – BPA Kalispell 115 kV line
- BPA Broadview – BPA Garrison 500 kV line 1
- BPA Broadview – BPA Garrison 500 kV line 2
- BPA Mill Creek – BPA Anaconda 230 kV line
- BPA Placid Lake – BPA Hot Springs 230 kV line
- Northwestern Thompson Falls – Avista Burke 115 kV line
- Northwestern Crow Creek –Avista Burke 115 kV line
- Northwestern Rattlesnake 230/161 kV transformer
- Northwestern Mill Creek – Garrison 230 kV line
- Northwestern Ovando – Garrison 230 kV line



Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service for this path since the last planning cycle.

Potential Long-Range Needs

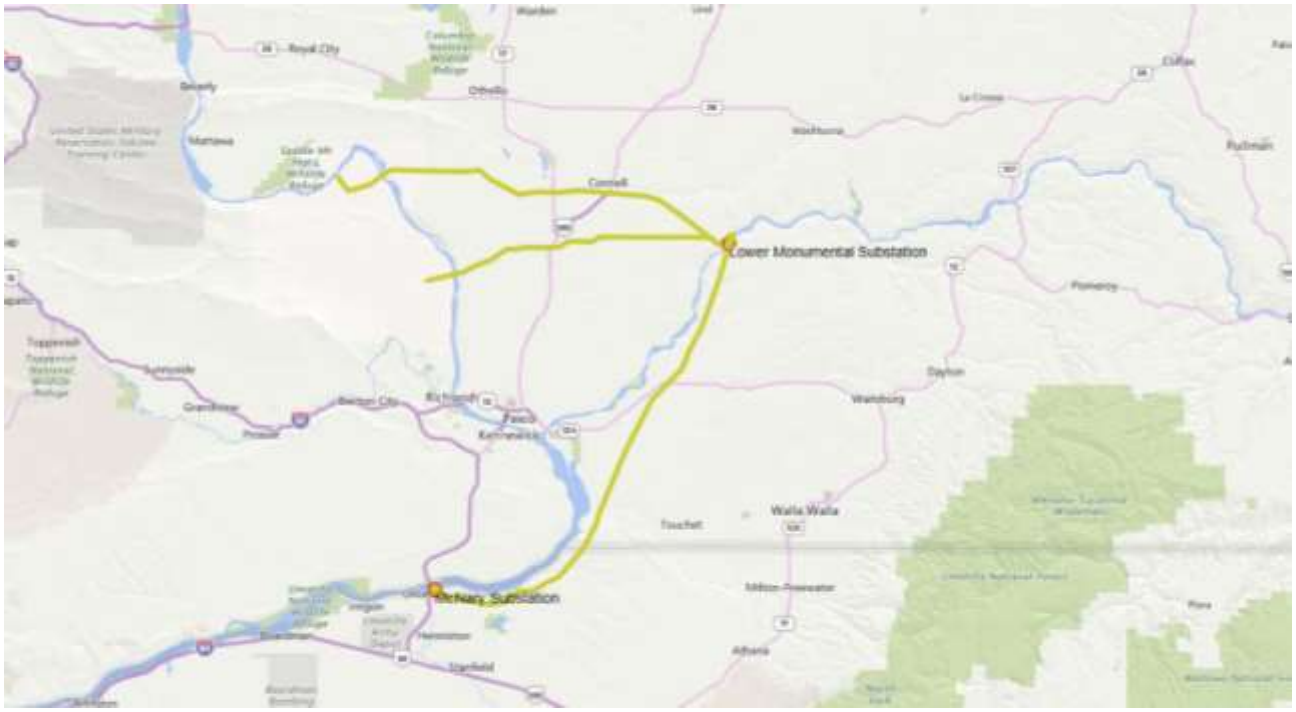
There are none identified for this path at this time.

West of Lower Monumental Path Description

This path is between Lower Monumental and McNary Substations. Historically, flow on the West-of-Lower Monumental path (WOLM) peaks during the late spring/early summer (May/June) time frame during spring run-off for both on and off-peak hours.

This path includes the following lines:

- Lower Monumental-Ashe 500 kV line
- Lower Monumental-Hanford 500 kV line
- Lower Monumental-McNary 500 kV line



Proposed Plans of Service

There are no proposed projects for this path at this time.

Recently Completed Plans of Service

There are no recently completed plans of service in this path since the last planning cycle.

Potential Long-Range Needs

There are none identified for this path at this time.

14. Appendix

This page is intentionally left blank.

14.1 List of Projects by Load Service Area

Area	Project Title	Project Number	Expected In-Service Date	Estimated Cost
1	**Seattle – Tacoma – Olympia**			
	Raver 500/230 kV Transformer (PSANI)	P00094	2020	$72,000,000
	Monroe-Novelty 230 kV Line Upgrade	P02367	2021	$1,000,000
	Tacoma 230 kV Series Bus Sectionalizing Breaker and Bus Tie Breaker	P02401	2021	$2,300,000
2	**Portland**			
	Forest Grove – McMinnville 115 kV Line Upgrade	P03261	2021	$1,800,000
	Carlton Upgrades	P01367	2021	$4,400,000
3	**Vancouver**			
4	**Salem – Albany**			
5	**Eugene**			
	Alvey 115 kV Bus Sectionalizing Breaker Addition	P02250	2022	$8,000,000
	Lookout Point – Alvey No. 1 and 2 Transfer Trip Addition	P03258	2022	$400,000
6	**Olympic Peninsula**			
	Kitsap 115 kV Shunt Capacitor Modification	P01443	2022	$4,000,000
7	**Tri-Cities**			
	McNary-Paterson Tap 115 kV Line	P02364	2022	$4,600,000
	Red-Mountain – Horn Rapids 115 kV Line Reconductor	P03102	2022	$3,700,000
	Jones Canyon 230 kV Shunt Reactor Addition	P00841	2022	$3,300,000
	Richland-Stevens Drive 115 kV Line	P02365	2024	$4,000,000
	South Tri-Cities Reinforcement	P03264	To be determined	To be determined
8	**Longview**			
	Longview 230/115 kV Transformer Addition	P02281	2022	$15,000,000
9	**Mid-Columbia**			
	Columbia 230 kV Bus Tie and Sectionalizing Breaker Addition and Northern Mid-Columbia Area Reinforcement (Joint Utility)	P00076	2021	$13,300,000
10	**Central Oregon – Alturas**			
	La Pine 115 kV Circuit Breaker Additions	P02467	2020	$280,000

11	**Southwest Washington Coast**			
	Holcomb-Naselle 115 kV Line Upgrade	P02261	2021	$10,400,000
	Aberdeen Tap to Satsop Park – Cosmopolis 115 kV Line Upgrade	P03506	2022	$191,000
12	**Spokane – Colville – Boundary**			
13	**Centralia – Chehalis**			
	Silver Creek Substation Reinforcements	P01092	2022	$2,200,000
14	**Northwest Montana**			
	Conkelley Substation Retirement	P02259	2024	$27,600,000
15	**Southeast Idaho – Northwest Wyoming**			
	Spar Canyon 230 kV Reactor Addition	P02306	2022	$3,800,000
16	**North Idaho**			
17	**North Oregon Coast**			
	Libby FEC 115 kV Shunt Capacitor Replacement or Restoration	P02366	2023	$1,500,000
18	**South Oregon Coast**			
	Fairview 115 kV Reactor Additions	P01465	2023	$10,300,000
	Central Oregon Coast O&M Flex (Toledo, Wendson, Santiam, Tahkenitch)	P02230	2023	$4,800,000
19	**DeMoss – Fossil**			
20	**Okanogan**			
	Grand Coulee – Foster Creek (Nilles Corner) 115 kV Line Upgrade	P03253	2021	$650,000
21	**Hood River – The Dalles**			
22	**Pendleton – La Grande**			
23	**Walla Walla**			
24	**Burley**			

Note: Projects in bold are newly identified transmission needs based on the most recent system assessment.

14.2 List of Projects by Path or Intertie

Area	Project Title	Path	Expected In-Service Date	Estimated Cost
1	**North of Hanford Path**			
2	**California to Oregon AC Intertie WECC Path 66 –North of John Day**			
3	**Pacific DC Intertie WECC Path 65**			
4	**West of Slatt – West of John Day – West of McNary Path**			
5	**Raver to Paul Path**			
	St. Clair – South Tacoma 230 kV Line Upgrade	R–P	2020	$400,000
	Raver 500/230 kV Transformer (PSANI)	R–P	2020	See Above
	Centralia Unit No. 2 Re-termination	R–P	2021	
6	**Paul to Allston – South of Allston Paths**			
	Holcomb – Naselle 115 kV Line Upgrade	P–A	2021	See Above
	Longview 230/115 kV Transformer Addition	SOA	2022	See Above
	Schultz-Wautoma 500 kV Line Series Capacitor	SOA	2021	$22,300,000
	Keeler 500 kV Reconfiguration and Breaker Additions	SOA	Beyond 2024	
	Keeler – Rivergate 230 kV Line Upgrade	SOA	Beyond 2024	
	Keeler 500/230 kV No. 2 Transformer Addition	SOA	Beyond 2028	
7	**West of Cascades South WECC Path 5**			
	Pearl – Sherwood 230 kV Corridor Reconfiguration	WOCS	Beyond 2027	
8	**Northern Intertie – North of Echo Lake Path – South of Custer Path**			
	Monroe 500 kV Line Retermination	NI	2020	$10,200,000
9	**West of Cascades North WECC Path 4**			
	Schultz – Raver 3 & 4 Reconductor and Series Capacitor	WOCN	Beyond 2028	
10	**West of Hatwai Path – Montana to Northwest WECC Path 8 – West of Lower Monumental Path**			

14.3 List of Line and Load Interconnection Projects

Project ID	Project Title	Status	Expected In-Service Year
P02280	L0381 NORTHERN LIGHTS SCHWEITZER MOUNTAIN RESORT	CONSTRUCTION	2019
P01374	L0365 PGES BLUELAKE-TROUTDALE-2	COMPLETION IN PROCESS	2019
P02313	L0316 PACIFICORP MCNARY SUBSTATION	CONSTRUCTION	2020
P03075	L0407 TOTTEN SUBSTATION METER INSTALLATION	CONSTRUCTION	2020
P00065	L0293 PACIFICORP - VANTAGE 23KV INTERCONNECTION	CONSTRUCTION	2020
P02240	L0346 AIRPORT SUBSTATION	CONSTRUCTION	2022
P02478	L0388 CHENOWETH SUBSTATION RIVERTRAIL SUPPORT	CONSTRUCTION	2022
P02454	L0389 UEC PHASE II	CONSTRUCTION	2022
P02994	L0415 PACIFICORP PROJECT VITESSE PONDEROSA SUBSTATION - PHASE 2	CONSTRUCTION	2022
P02256	L0380 QUENETT CREEK SUBSTATION	CONSTRUCTION	2028

The list of interconnection projects provided above include only those projects where the plan of service is well-defined, have a project schedule, and are in the construction phase or completion is in process.

14.4 List of Generation Interconnection Projects

Project ID	Project Title	Status	Expected In-Service Year
P01234	MIDWAY-STATION SERVICE ENGINE GENERATOR UPGRADE G00153	COMPLETION IN PROCESS	2019
P02300	G0514 HARP SOLAR PROJECT	COMPLETION IN PROCESS	2019
P02660	NEWSUN HARNEY SOLAR 1 G0520 G0522	CONSTRUCTION	2019
P02342	G0409, G0410, G0376, G0379 FOSSIL LAKE SOLAR	CONSTRUCTION	2020
P02303	G0505 OSU PACIFIC MARINE ENERGY CENTER	CONSTRUCTION	2020
P00752	G0416 GREENWING CHRISTMAS VALLEY SOLAR PROJECT	COMPLETION IN PROCESS	2020

The list of interconnection projects provided above include only those projects where the plan of service is well-defined, have a project schedule, and are in the construction phase or completion is in process.

14.5 List of Projects Expected to be Energized

Area	Project Title	Project Number	Expected In-Service Date	Estimated Cost
2	**Portland**			
	Keeler 500/230 kV Transformer Re-termination	P02227	2019	$1,600,000
4	**Salem**			
	Salem-Chemawa 115 kV Line Disconnect Switches	P02491	2019	$1,200,000
13	**Centralia – Chehalis**			
	Paul Reactor Addition	P00667	2019	$1,700,000
15	**Southeast Idaho – Northwest Washington**			
	Palisades-Snake River Transfer Trip Addition	P03256	2019	$200,000
19	**DeMoss – Fossil**			
	DeMoss 69 kV Shunt Capacitor (3.5 Mvar) Addition	P02241	2019	$5,000,000

Path	Project Title	Project Number	Expected In-Service Date	Estimated Cost
2	**California to Oregon AC Intertie WECC Path 66 –North of John Day**			
	Central Oregon Series Capacitor: Slatt Series Capacitor Addition and Bakeoven Series Capacitor Upgrade	P02455	2019	$13,500,000

Note: Most projects go into service as expected. In some instances a project's expected in-service date maybe revised during development of this report or after it is published. Therefore, a project's expected in-service date may be revised reflecting a later in-service date.

14.6 System Assessment Historical and Forecast Peak Load by Area

2019 System Assessment Historical and Forecast Load Information

The following table lists the load areas in the 2018 System Assessment along with their actual historical peak loads for both the summer and winter seasons. In addition, for each load area, there is a comparison of the load forecasts between the 2015/16 and 2017/18 System Assessments. The table shows the forecast summer and winter peak loads for the near term (2020 and 2022) and long term (2024 and 2027). The 2015/16 System Assessment used the forecasts shown for the years 2020 (near term) and 2024 (long term). The 2017/18 System Assessments used the forecasts shown for the years 2022 (near term) and 2027 (long term). This table indicates how the load forecasts changed between the 2015/16 and 2017/18 System Assessments and how each of these forecasts compares with historical peak load data. For the historical peak values, bold text indicates the **season** with the highest peak load for that area. Several of the Load Areas have a higher historical peak than the forecasted load being planned for. This is due to either a) the historical peak was reached in a year that had extreme weather or temperature that is not an expected condition, or b) the load forecast in the area is trending down due to lower expected load growth.

		Historical		2018 Assessment Near Term		2019 Assessment Near Term		2018 Assessment Long Term		2019 Assessment Long Term	
No.	LOAD AREAS	Historical Peak Load (MW)		2022 Peak Load Forecast (MW)		2023 Peak Load Forecast (MW)		2027 Peak Load Forecast (MW)		2028 Peak Load Forecast (MW)	
		Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
1	Seattle-Tacoma-Olympia[1]	6644	**9123**	7029	9408	6699	9438	7184	9566	6792	9565
2	Portland	4022	**4136**	3848	3763	3910	3912	4105	3811	4129	4137
3	Vancouver	864	**1082**	783	1017	790	1012	805	1046	913	1017
4	Salem - Albany[2]	840	**895**	839	924	880	973	878	962	907	952
5	Eugene	602	**896**	609	831	609	775	685	888	727	780
6	Olympic Peninsula	742	**1284**	791	1265	852	1404	817	1287	827	1356
7	Tri-Cities	**1158**	1007	1185	987	1342	1089	1245	1084	1404	1137
8	Longview	646	**830**	686	800	678	873	707	821	674	876
9	Mid-Columbia[3]	2162	**2452**	2278	2312	2563	2897	2531	2587	2550	3033
10	Central Oregon	532	**687**	528	695	530	697	548	723	605	789
11	SW Washington Coast	184	**353**	269	381	286	421	282	391	300	430
12	Spokane	896	**924**	885	910	828	858	895	930	891	893
13	Centralia/ Chehalis	134	**235**	175	276	169	263	179	282	173	270
14	NW Montana	259	**354**	306	418	268	373	361	420	284	399
15	SE Idaho - NW Wyoming	146	**292**	149	314	153	309	157	338	161	333
16	North Idaho[4]	101	**188**	122	191	122	191	123	199	123	199
17	North Oregon Coast	141	**270**	187	291	187	291	190	300	197	304
18	South Oregon Coast	259	**505**	245	425	268	476	249	434	272	534
19	De Moss - Fossil	29	**44**	23	32	30	36	24	32	31	38
20	Okanogan	158	**232**	171	250	201	270	189	270	213	302
21	Hood River - The Dalles[5]	221	**274**	373	422	373	422	457	507	457	507
22	Pendleton / La Grande	**146**	139	151	143	151	143	150	142	150	142
23	Walla Walla[6]	**91**	66	98	82	153	133	112	95	164	145
24	Burley	**192**	154	207	147	193	134	213	150	197	136

Historic numbers in **Bold** font indicate which season has a higher peak load for that area

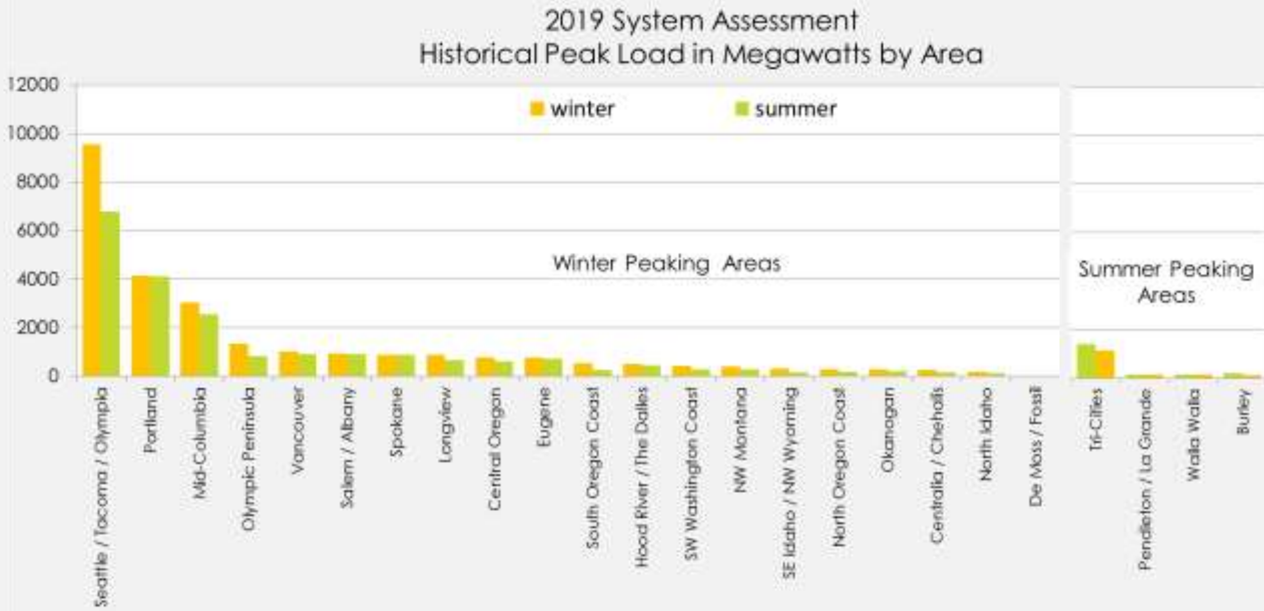
14.7 Load Growth by Area

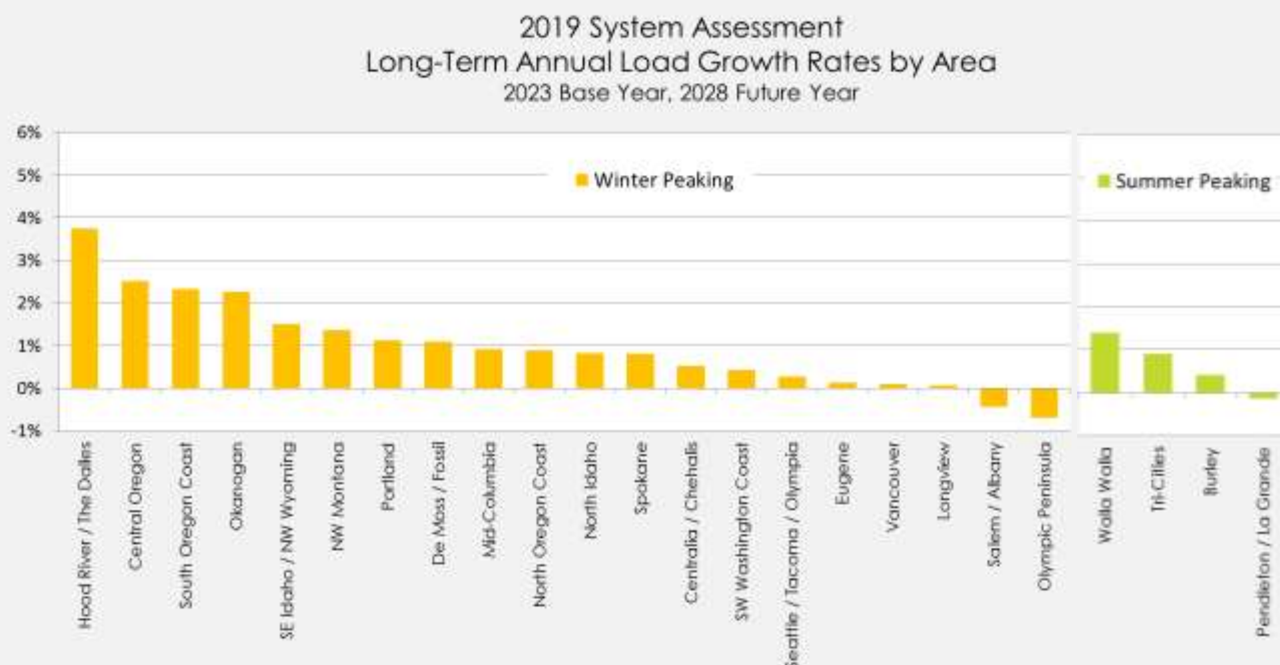
2019 System Assessment Long-Term Peak Load Growth by Area

	Load Areas	2019 Assessment: 2023 Peak Load Forecast Near Term, 5 year (MW)		2019 Assessment: 2028 Peak Load Forecast Long Term, 10 year (MW)		Growth: Long-Term Annual Load Growth Rate, 2023 Base, 2028 Future (%)	
		Summer	Winter	Summer	Winter	Summer	Winter
1	Seattle / Tacoma / Olympia	6699	9438	6792	9565	0.3	0.3
2	Portland	3910	3912	4129	4137	1.1	1.1
3	Vancouver	790	1012	913	1017	2.9	0.1
4	Salem / Albany	880	973	907	952	0.6	-0.4
5	Eugene	609	775	727	780	3.6	0.1
6	Olympic Peninsula	852	1404	827	1356	-0.6	-0.7
7	Tri-Cities	1342	1089	1404	1137	0.9	0.9
8	Longview	678	873	674	876	-0.1	0.1
9	Mid-Columbia	2563	2897	2550	3033	-0.1	0.9
10	Central Oregon	530	697	605	789	2.7	2.5
11	SW Washington Coast	286	421	300	430	1.0	0.4
12	Spokane	828	858	891	893	1.5	0.8
13	Centralia / Chehalis	169	263	173	270	0.5	0.5
14	NW Montana	268	373	284	399	1.2	1.4
15	SE Idaho / NW Wyoming	153	309	161	333	1.0	1.5
16	North Idaho	122	191	123	199	0.2	0.8
17	North Oregon Coast	187	291	197	304	1.0	0.9
18	South Oregon Coast	268	476	272	534	0.3	2.3
19	De Moss / Fossil	30	36	31	38	0.7	1.1
20	Okanogan	201	270	213	302	1.2	2.3
21	Hood River / The Dalles	373	422	457	507	4.1	3.7
23	Pendleton / La Grande	151	143	150	142	-0.1	-0.1
22	Walla Walla	153	133	164	145	1.4	1.7
24	Burley	193	134	197	136	0.4	0.3
	All Areas	22235	27390	23141	28274	0.8	0.6

* The long-term annual growth rate is calculated as follows:
(Future Year in MW 2028 - Base Year in MW 2023)^(1/(2028-2023)) * 100 -100
Historic numbers in **bold** font indicate which season has a higher peak load for that area.

14.8 Historical Peak Loads & Long-Term Annual Growth Rates by Area





The long-term annual growth rate is calculated as follows:
(Future Year in MW 2028 - Base Year in MW 2023)^(1/(2028-2023)) * 100 -100

14.9 2019 Cluster Study Summary Results

2019 Cluster Study: Summary Results

Table 1, below, lists the reinforcements identified in the 2019 TSEP Cluster Study (CS), the associated estimated direct cost, and an estimated energization date for each project. Table 1 summarizes system reinforcement projects on the BPA-TS Network that would be required to accommodate one or more of the 2019 TSEP CS TSRs. The estimated direct project costs do not include overhead loadings. The projected energization date provides an indication of the time that might be needed to complete the project assuming completion of preliminary engineering, environmental review, and construction; it assumes that these efforts would start upon execution of preliminary engineering agreements under the TSEP.

Table 1 does not list project requirements associated with fixes or other mitigations to third-party systems. Those requirements will, however, need to be addressed before commencement of service can begin for those affected TSRs. BPA-TS has identified potential impacted third-party transmission systems following Table 1.

Table 1: 2019 Cluster Study Plan(s) of Service and Estimated Costs

Plan of Service	Direct Cost ($M)	Energization Date
Raver-Paul Reinforcements • Covington-Chehalis 230 kV Reconductor • Westside-RAS Modification • Schultz-Wautoma 500 kV Series Compensation	 $12.5 N/A[1] N/A[2]	 Fall 2024 Spring 2020 Fall 2023
La Pine-Area projects • La Pine 230/115 kV #1 Transformer Replacement • La Pine-Fort Rock 115 kV #2 new radial circuit	 $7.5 $70.0	 Fall 2025 Fall 2027
South of Allston • Schultz-Wautoma 500 kV Series Compensation	 N/A[2]	 Fall 2023
Satsop-Area project • AberdeenTap-Satsop Park 115 kV re-sag/reconductor	 $0.5	 Fall 2024
Walla Walla Project (identified in prior Cluster Study)	$15.5	Fall 2027
South Tacoma-St. Clair (identified in prior Cluster Study)	N/A[3]	Fall 2019
Garrison-Bell-Ashe[4] (identified in prior Cluster Study) or Montana Non-Wire Solution	$1,330.0 (Garrison-Bell-Ashe only)	Fall 2029
Total	**$1,436.0**	

Additional information is available at https://www.bpa.gov/transmission/CustomerInvolvement/TSRStudyExpansionProcess/Documents/2019-cluster-study-summary-results.pdf

14.10 List of Acronyms

Acronym	Title
Alder	Alder Mutual Light Company
AC	Alternating Current
ARM	Alternative Review Meeting
ATC	Available Transfer Capability
AVA	Avista Corp
BCTC	British Columbia Transmission Corporation
BPA	Bonneville Power Administration
BPUD	Benton Public Utility District
BREA	Benton Rural Electric Association
CS	Cluster Study
CAA	Clean Air Act
CAISO	California Independent System Operator
CBF	City of Bonners Ferry
CCCT	Combined-Cycle Combustion Turbine
CEC	Central Electric Coop
Chelan	Chelan County Public Utility District
CIFP	Commercial Infrastructure Financing Proposal
CIP	Capital Investment Portfolio
Clark	Clark Public Utilities
COE	City of Eatonville
COI	California Oregon Intertie
COS	City of Steilacoom
CPP	Clean Power Plan
Cowlitz	Cowlitz Public Utility District
DOE	Department of Energy
Douglas	Douglas County Public Utility District
EIM	Energy Imbalance Market
EL&P	Elmhurst Light and Power
Emerald	Emerald Public Utility District
EPA	Energy Protection Agency

ETC	Existing Transfer Commitments
EWEB	Eugene Water and Electric Board
FAS	Interconnection Facilities Study
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FEC	Flathead Electric Cooperative
FERC	Federal Energy Regulatory Commission
FES	Interconnection Feasibility Study
GI	Generator Interconnection
HVDC	High Voltage Direct Current
IPC	Idaho Power Company
ISIS	Interconnection System Impact Study
LADWP	Los Angeles Department of Water and Power
LGI	Large Generator Interconnection
LGIA	Large Generator Interconnection Agreement
LGIP	Large Generator Interconnection Procedure
LL&P	Lakeview Light and Power
LLI	Line and/or Load Interconnection
LT ACT	Long-Term Available Transfer Capability
LTF	Long-term Firm
LVE	Lower Valley Energy
M2W	Montana to Washington
MEC	Midstate Electric Cooperative
Milton	City of Milton
MT-NW	Montana-Northwest
Mvar	Mega Volt-Amphere reactive
NEPA	National Environmental Policy Act
NERC	North America Electric Reliability Corporation
NWE	Northwestern Energy
NITS or NT	Network Integration Transmission Service
NI-W	Northern Intertie West
NLI	Northern Lights, Inc.
NOEL	North of Echo Lake
NOS	Network Open Season

NPCC	Northwest Power and Conservation Council
NW-CA	Northwest to California
OATT	Open Access Transmission Tariff
OML	Ohop Mutual Light
PA	Paul-Allston
PAC	PacifiCorp
PC	Planning Coordinator
PCM	Project Coordination Meeting
PDI	Project Delivery Information
PDCI	Pacific Direct Current Intertie
PDT	Project Definition Team
PEFA	Planning and Expansion Functional Agreement
PGE	Portland General Electric
PI	Peninsula Light
PL&P	Parkland Light and Power
PMU	Phasor Measurement Unit
PNW	Pacific Northwest
PNUCC	Pacific Northwest Utilities Conference Committee
POD	Point of Delivery
POR	Point of Receipt
POS	Plan of Service
PPOS	Proposed Plan of Service
PRD	Project Requirement Diagram
PSA	Puget Sound Area
PSE	Puget Sound Energy
PSM	Project Strategy Meeting
PTC	Production Tax Credit
PTP	Point-to-Point
PTDF	Power Flow Distribution Factor
RAS	Remedial Action Scheme
RP	Raver-Paul
RRO	Regional Reliability Organization
SCL	Seattle City Light
7th Plan	Northwest Power and Planning Council's Seventh Power Plan

SIS	System Impact Study
SMI	Small Generator Interconnection
SOA	South of Allston
SOB	South of Boundary
SGIP	Small Generator Interconnection Process
SPUD	Snohomish County Public Utility District
SVEC	Surprise Valley Electrification Corporation
TI	Technology Innovation
TIP	Technology Innovation Project
TLS	Transmission Load Service
TP	Transmission Planners
TPL	Transmission Planning Standard
T-Plan	Transmission Plan
TPU	Tacoma Power Utilities
TS	Transmission Service
TSEP	Transmission Service Requests and Expansion Process
TSR	Transmission Service Request
TTC	Total Transfer Capability
UEC	Umatilla Electric Co-op
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
WEC	Wasco Electric Cooperative
WECC	Western Electricity Coordinating Council
WOCN	West of Cascades North
WOCS	West of Cascades South
WOH	West of Hatwai
WOJ	West of John Day
WOLM	West of Lower Monumental
WOM	West of McNary
WOS	West of Slatt
WPUD	Whatcom Public Utility District

B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

BPA TRANSMISSION PLAN
Transmission Planning
7600 NE 41st Street
One Park Place
Third Floor
Vancouver, WA
360-619-6775